Historical Hydropower Operations and Economic Value

March 2020

T.D. Veselka
Q. Ploussard
M. Christian

Energy Systems Division, Argonne National Laboratory

Acknowledgments

This work was authored by Argonne National Laboratory, operated by UChicago Argonne, LLC, and supported by the HydroWIRES Initiative of the Energy Department's Water Power Technologies Office, under award or contract number DE-AC02-06CH11357.

Context

HydroWIRES

The U.S. electricity system is changing rapidly with the large-scale addition of variable renewables. The flexible capabilities of hydropower (including pumped storage hydropower) position it well to aid in integrating these variable resources while supporting grid reliability and resilience. Recognizing these challenges and opportunities, the U.S. Department of Energy (DOE) Water Power Technologies Office (WPTO) launched a new initiative known as HydroWIRES: Water Innovation for a Resilient Electricity System. HydroWIRES focuses principally on understanding and supporting the changing role of hydropower in the evolving U.S. electricity system. Through the HydroWIRES initiative, WPTO seeks to understand and drive utilization of the full potential of hydropower resources to contribute to electricity system reliability and resilience, now and into the future.

HydroWIRES is distinguished in its close engagement with the U.S. Department of Energy (DOE) national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the DOE portfolio that add significant value to the HydroWIRES initiative.

HydroWIRES operates in conjunction with the DOE Grid Modernization Initiative, which focuses on developing new architectural concepts, tools, and technologies that measure, analyze, predict, protect, and control the grid of the future, and on enabling the institutional conditions that allow for quicker development and widespread adoption of these tools and technologies.

Connections with the HydroWIRES Roadmap

This report on historical hydropower operations and economic value focuses primarily on addressing HydroWIRES Objective 1.3: Advance valuation of conventional and pumped-storage hydropower assets. It is informed by previous work performed by Argonne and other national laboratories on the modeling and analysis of value of pumped storage and conventional hydropower. The results from this report will feed into the new projects that are planned under the HydroWIRES initiative and that will examine hydropower's value in providing grid reliability and resilience, as well as in improving the modeling and representation of hydropower in power system models. Other relevant DOE efforts include various WPTO-funded projects, such as the Beyond Levelized Cost of Energy Project and Integrated Hydropower and Storage Systems, that are currently addressing similar challenges associated with defining grid service values that arise from hydropower machine capabilities.

Disclaimer

This page left intentionally blank.

ANL-20/06

Historical Hydropower Operations and Economic Value

Historical Hydropower Value

T.D. Veselka
Q. Ploussard
M. Christian

Energy Systems Division, Argonne National Laboratory

March 2020

Work sponsored by the U.S. Department of Energy

Acronyms and Abbreviations

$/MWh	dollar(s) per megawatt-hour
ABB	Asea Brown Boveri Ltd
AEO	annual energy outlook
AF	acre-foot (feet)
AFUDC	allowance for funds used during construction
AGC	automatic generation control
APS	Arizona Public Service (system name)
Argonne	Argonne National Laboratory
ASCC	Alaska Systems Coordinating Council
AZPS	Arizona Public Service (BA and BAA name)
BA	Balancing Authority
BAA	Balancing Authority Area
BM	Blue Mesa reservoir
BPA	Bonneville Power Administration
CAISO	California Independent System Operator (market operator name)
CAMX	California–Mexico
cfs	cubic foot (feet) per second
CISO	California Independent System Operator (BA and BAA name)
CRSP	Colorado River Storage Project
CY	Crystal reservoir
DP	dynamic program
DSM	demand-side management
DSW	Desert Southwest
EERE	Office of Energy Efficiency & Renewable Energy (Office of the DOE)
EFOR	equivalent forced outage rate
EI	Eastern Interconnection
EIA	Energy Information Administration
EIM	energy imbalance market
EIS	environmental impact statement
EMCAS	Electricity Market Complex Adaptive System

ENS	energy not served
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FES	Firm Electric Service
FG	Flaming Gorge reservoir
flex-reg	flexible regulation
FN	Fontenelle reservoir
FRCC	Florida Reliability Coordinating Council
FSF	fall steady flows
GADS	Generating Availability Data System
GCD	Glen Canyon Dam
GW	gigawatt(s)
GWh	gigawatt-hour(s)
HFE	high-flow experiment
HICC	Hawaii Island Coordinating Council
IRP	integrated resource plan
ISO	independent system operator
LAP	Loveland Area Project
LDC	load duration curves
LMP	locational marginal price
LOLP	loss-of-load probability
LP	linear programming
LSSF	low summer steady flow
LTEMP	Long-Term Experimental and Management Plan
MILP	mixed integer linear programming
MISO	Midcontinent Independent System Operator
MLFF	modified low fluctuating flow
MP	Morrow Point reservoir
MRO	Midwest Reliability Organization
MW	megawatt(s)
MWh	megawatt-hour(s)

NERC	North American Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	net present value
NREL	National Renewable Energy Laboratory
NVE	NV Energy
NYISO	New York Independent System Operator
O&M	operation and maintenance
ORNL	Oak Ridge National Laboratory
PAC	PacifiCorp
PACE	PAC East
PACW	PAC West
PGE	Portland General Electric
PSCO	Public Service Company of Colorado
PSE	Puget Sound Energy
PSH	pumped storage hydropower plants
PUD	Public Utility District
RE	regional entity
RFC	Reliability First Corporation
RM	reserve margin
RMRG	Rocky Mountain Reserve Group
ROD	Record of Decision
ROR	run-of-river
RPS	renewables portfolio standard
RTO	Regional Transmission Organization
SCADA	supervisory control and data acquisition
SERC	SERC Reliability Corporation
SF	steady flow
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TEPPC	Transmission Expansion Planning Policy Committee
TRE	Texas Regional Entity

U.S.	United States
USBR	U.S. Bureau of Reclamation
Var	volt-ampere reactive
VERs	variable energy resources
W	watt(s)
WACM	Western Area Power Administration, Colorado Missouri
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
YRSF	year-round steady flow

This page left intentionally blank.

Contents

Contents (Cont.)

Figures

Figures (Cont.)

Figures (Cont.)

Figures (Cont.)

Tables

This page left intentionally blank.

1.0 Introduction

Hydropower infrastructure is generally long-lived; several plants in the United States of America have been operating for over 100 years. The first hydropower plant in the United States began operations along the Fox River in Appleton, Wisconsin, in 1882. The U.S. hydropower industry has expanded over the years, and today has approximately 101 GW of nameplate hydropower generation capacity (Figure 1-1) accounting for about 7.1% of the nation's total annual electricity production. In 2015, it accounted for almost half of U.S. renewable energy generation. This report provides an overview of the economic value of U.S. hydropower with an emphasis on those resources that reside in the Western Interconnections (WIs).

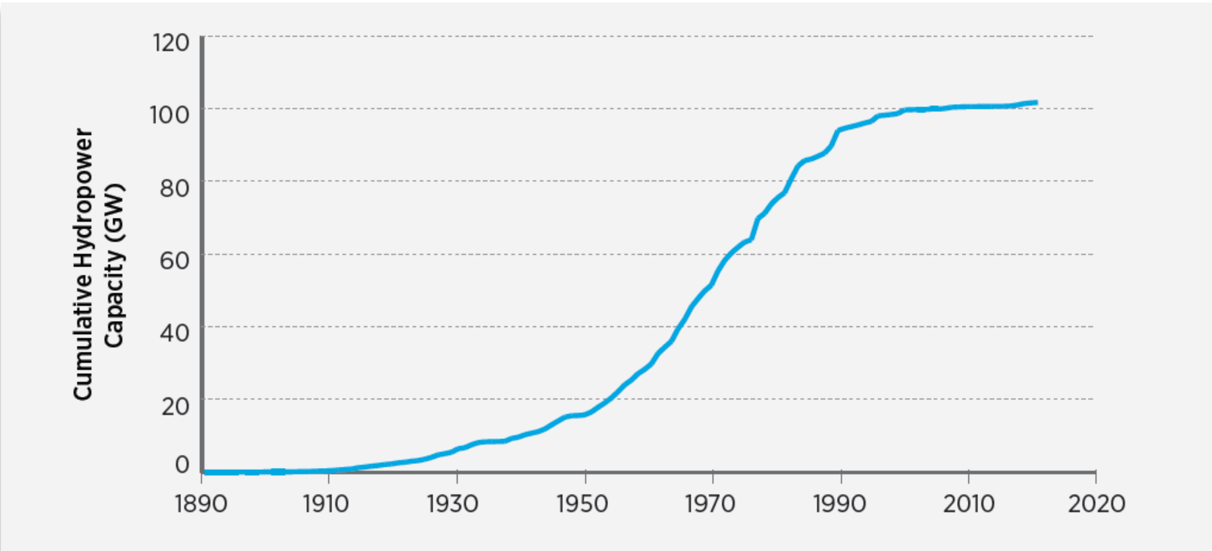


Figure 1-1 Evolution of the Cumulative Hydropower Capacity in the United States (HydroVision and DOE 2016)

The nation's hydropower plants are renewable energy assets that use the force of flowing water to produce electricity. The amount of power they generate depends on the elevation difference between a water source above the hydropower plant and the tailwater/afterbay below it. Production also depends on the volume of water that, through gravitational forces, flows through a power plant's turbine. At the turbine, energy is transferred to a turbine runner or other rotating element to spin a shaft connected to an electric generator that produces power.

Hydropower capacity and energy production have high economic value within the U.S. power sector; they provide very reliable low-cost, low-carbon, renewable energy, as well as flexible grid support services.[1] The value of a specific hydropower resource is based on its ability to provide the grid with firm capacity, flexible generation, and ancillary grid services. Hydropower also has value because its power production under most situations reduces systemic levels of air pollutants and greenhouse gas emissions by displacing generation that, if not for hydropower electricity production, would have been generated by fossil-fired power plants.

---

[1] DOE, 2016, *Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source*, DOE/GO-102016-4869. Oak Ridge, TN: DOE. https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

Value varies widely among U.S. hydropower plants based on many factors including, but not limited to, water availability (i.e., hydrological conditions), plant operational flexibility, generating unit water-to-power conversion efficiency, location, and the characteristics of the power grid in which it resides. Essentially, hydropower plants that are capable of producing energy and serving the grid when needed the most have the highest value. These high-valued hydropower resources are typically the ones that are dispatchable and capable of producing high levels of power at the time of the net peak demand. This net demand equals the system load minus variable energy resources (VERs) production.

This section qualitatively discusses hydropower value primarily through an economic lens, a measure of social welfare that focuses on the savings that it brings to the U.S. economy. More specifically, it discusses historical hydropower contributions and economics in each U.S. interconnection, including the WI, the Eastern Interconnection (EI), and the Electric Reliability Council of Texas (ERCOT) (Figure 1-2). EI hydropower contributions are further disaggregated in North American Reliability Corporation (NERC) regions and the WI is detailed at the Balancing Authority Area (BAA) level.

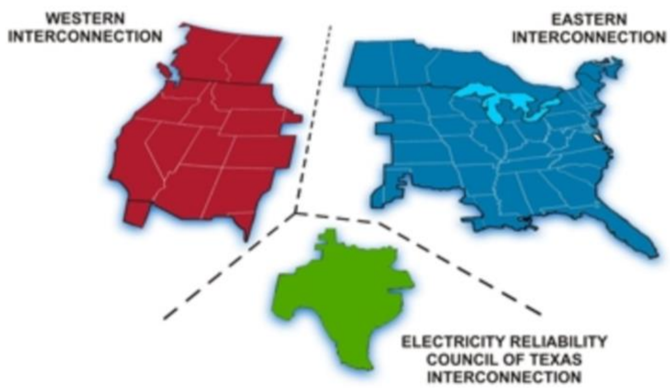


Figure 1-2 U.S. Power Grid Interconnections

All operational hydropower plants bring economic value to the electric utility sector on time scales ranging from fractions of a second to several decades by providing the grid with capacity, energy, ancillary services and other support functions (e.g., inertia).

The economic value of hydropower energy production is its social value, which is an integral part of modern life. This is captured by the value of foregone opportunity; that is, the cost to produce power by the next-best alternative supply resource. Because electricity on a utility scale cannot be stored economically in large quantities, it differs from other types of goods. It differs from, for example apples, because if the supply of apples at any given moment, and at every point when apples are consumed, falls short of supply, consumers can live a normal life without apples. Apples and apple products can also be stored and consumers can find substitutes or go without. This is not true for many uses/applications of electricity. If there is a lack of the exact supply to meet demand at every consumption point and at every time electrical demand exists, this disrupts society. In this regard, electrical capacity is a public good (in the economic sense).

Electrical capacity has value in its ability to produce electricity. The value of hydropower capacity is the construction cost of diverting resources to build a replacement power plant with equal characteristics. This presumes that construction costs are the same as market value and that market value is the same as social value. These assumptions are valid under conditions of fair, competitive markets.

Economic benefits in this report focus on run-of-river (ROR) and conventional hydropower[2] value in terms of:

- **Energy** through a more efficient and less costly grid-level dispatch, and
- **Firm capacity** through the delayed creation/deployment of new resources.

All ROR and conventional hydropower technologies rely on limited or scarce water resources. This section expresses hydropower economic value that use these limited resources as avoided grid costs.[3] The avoided cost approach measures the interconnection-level economic impacts that would occur if an existing hydropower resource was removed from the system. The avoided cost approach therefore uses a systemic approach based on a comparison of total grid unit-commitment and production costs between "with" (factual) and "without" (counterfactual) hydropower resource(s) cases. This report focuses primarily on avoided costs related to capacity expansion and plant-level energy production.

From an operational perspective, avoided costs attributed to hydropower energy production, ancillary services, and other grid benefits such as inertia are all reflected in grid-level changes in production costs that are encapsulated in the system dispatch.[4] That is, from an economic standpoint all of these hydropower value streams are based on a single "bundled" reduction in system-level dispatch cost. Assigning values to individual components is difficult because intertwined feedbacks are problematic to untangle without assigning allocation rules that are somewhat arbitrary. Untangling is also unnecessary from an economic viewpoint because a systems approach measures all-encompassing cost impacts as opposed to the attribution of costs/benefits to individual entities that participate in grid supply and demand activities.[5]

Analysis of hydropower included in this report is not a total economic value study. It is important to note that the value of hydropower is much broader than the economic contributions outlined in the body of this report. These additional contributions include (but are not limited to): fish and wildlife, navigation, water supply, recreation, flood control, and irrigation. A 2015 investigation into these values conducted at Oak Ridge National Laboratory (ORNL) by Bonnet et al. found that in a majority of federal hydropower facilities (Tennessee Valley Authority, U.S. Bureau of Reclamation [USBR], and U.S. Army Corps of Engineers) the benefit associated with the power produced is significantly less than those provided by other benefits such as irrigation or recreation, and has roughly the same value proposition as water supply

---

2 Conventional hydropower refers to the use of dams or impoundments to store water in a reservoir; water released from the reservoir flows through a turbine to generate electricity (Office of Energy Efficiency & Renewable Energy [EERE], 2010, "Wind and Water Power Program," DOE/GO-102010-3040, DOE, July. https://www.nrel.gov/docs/fy10osti/48642.pdf).

3 Scarcity relates to the use of limited resources and associated opportunity/avoided costs involved in making economic decisions. Economics solves the problem of scarcity by placing higher prices on scarce goods. A high price discourages demand and encourages firms to develop alternatives (https://www.economicshelp.org/blog/586/markets/scarcity-in-economics/).

4 From an economic perspective, all costs are ultimately attributed to expenditures related to power production including impacts of unit wear and/or costs (either direct or indirect) to reliably serve grid loads. Factors such as redispatch for congestion, or unit back-down to provide ancillary services for system reliability or to provide inertia for system stability, are reflected in grid dispatch/production cost. Note that some of economic values provided by hydropower operations are difficult to measure using the state-of-the-art production-cost models. In addition, some values are currently not monetized in energy markets (e.g., inertia).

5 Entities may be financially compensated for energy production and for providing both capacity and grid services through various market mechanisms; however, monetary transactions and financial arrangements among grid entities within the overall system are not part of the economic calculus.

benefits.[6] The identification and quantification of these benefits also represent a core factor of the DOE HydroWIRES initiate, which is focused on articulating the value of hydropower to an evolving grid. The provision of nonmarket value largely applies to two research areas: (1) value under evolving system conditions and (2) capabilities and constraints. Although in many cases there is significant value to supporting the evolving grid, it is important to understand that hydropower's role and value is a function of its temporal mode of operation in conjunction with the attributes of the grid in which it resides.[7] The importance of understanding the holistic value of hydropower is demonstrated in HydroWIRES current flagship effort, which focuses on developing a standardized technoeconomic valuation method for pumped storage hydropower. This work recognizes that developing a pumped storage field requires that the host of benefits provided by the facility can be demonstrably established using a neutral valuation.[8]

---

6 Bonnet, M., A. Witt, K. Stewart, B. Hadjerioua, and M. Mobley, 2015, *The Economic Benefits of Multipurpose Reservoirs in the United States-Federal Hydropower Fleet,* ORNL/TM-2015/550, Oak Ridge National Laboratory, September. https://info.ornl.gov/sites/publications/files/Pub59281.pdf.

7 EERE, 2019, "HydroWIRES Overview," DOE/GO-102019-5195, July. https://www.energy.gov/sites/prod/files/2019/08/f65/Hydrowires%20Overview%202019.pdf.

8 EERE, 2018, "Pumped Storage Projects Selected for Techno-Economic Studies," December 3. https://www.energy.gov/eere/articles/pumped-storage-projects-selected-techno-economic-studies.

2.0 Hydropower Capacity

The maximum amount of power a hydropower plant can produce at any moment in time depends on the availability of water, which fluctuates as a function of naturally occurring hydrological forcing processes (rain, snowfall, evaporation, etc.) and the operation of water flow control/diversion structures (e.g., water storage reservoirs) in the basin/sub-basin. At times, but not always, the maximum output is also influenced by institutional operating criteria such as, but not limited to, those designed to deliver water to downstream entities and to enhance and/or protect downstream riverine environmental resources.

This maximum potential has value because it enables the plant to serve grid loads and provide ancillary services. In general, the higher the power plant output potential the greater its value. For example, a plant that has a high output potential can generate greater amounts of energy when it has a high economic value, as compared to a plant that has a lower output potential. Similarly, a large output potential enables the plant to provide higher levels of ancillary services. The ability to generate power at the time of peak load and/or when ancillary services are the highest, however, ultimately dictates resource economic value. For example, a large ROR hydropower plant that only produces power during off-peak times of the year has little or no economic capacity value because it does not contribute toward the system capacity reserve margin (RM). In addition, ROR plants typically do not provide any ancillary services.

For the purpose of this report, the following metrics are used to describe generating unit and power plant capabilities:

- **Nameplate Capacity:** The manufacturer designed maximum output of a generator.

- **Maximum Potential Output:** The maximum potential output of a generator is the highest production level that can be <u>physically</u> achieved without <u>institutional constraints</u>/limitations under ideal hydropower conditions (e.g., full reservoir, large hydraulic head, with no equipment outages). It may be either higher or lower than the nameplate capacity, typically changing either very slowly over time as a result of equipment degradation or relatively quickly; for example, when a unit is upgraded.[9]

- **Physical Maximum Output:** The physical maximum amount of output a generating unit at a specific point in time. It is volatile, fluctuating as a function of hydropower condition (e.g., hydraulic head/inflows) and of the state of the generator (e.g., on/off/partial outage).

- **Operational Maximum:** The operational maximum is the highest output that can be obtained under normal operating conditions. Some hydropower units/plants cannot attain their physical maximum output under all situations/hydropower states because of institutional operating criteria such as reservoir restrictions, environmental flow criteria, and/or downstream water delivery obligations.

- **Maximum Setpoint:** The maximum dispatched setpoint production level to serve load during a dispatch interval as constrained by physical limitations and is some situations by more stringent restrictions specified by either environmental operating criteria or other institutional practices. Hydropower generation levels deviate from the setpoint in response to either 4-second automatic

[9] Hydropower output can sometimes exceed the nameplate rating. For example, prior to the mid-1980s, the Glen Canyon Power Plant routinely operated above its nameplate capacity because of mica-tip turbine windings.

generation control (AGC) signals when a unit provides regulation services or when contingency reserves (i.e., spinning and non-spinning reserves) are deployed.[10]

- **Firm Capacity Credit:** The plant's *firm capacity credit* is used in system RM calculations such as those made for long-term integrated resources planning (IRP). Different plant owners/operators use different criteria to determine the firm capacity credit of a hydropower plant. It is often based on the probability that the projected operational maximum output of a generator will be either at the firm capacity level or higher during the system peak load. This probability level is set by the utility that conducts the IRP, as reflected in its risk tolerance level. In some cases, the firm capacity credit is based on the higher physical maximum output when the power plant is granted operational criteria exceptions under grid emergencies.

This section of the report focuses on nameplate capacity and the firm capacity credit for long-term planning. Section 8 focuses on the other components of capacity that in general are used to describe hydropower operations that range from week-ahead scheduling through real-time operations.

2.1 Overview of Hydropower Capacity Contributions to the U.S. Electricity Sector

The United States has approximately 101 GW of nameplate hydropower generation capacity. As shown in Figure 2-1, in 2016, hydropower in the United States represented 9.6% of the total nameplate capacity.[11] At least 40% of this hydropower capacity is composed of pumped-storage and "peaking" hydropower plants, which can store water to produce electricity in the future. At least 18% is composed of ROR plants, which can only produce electricity when water is flowing.[12] A total of 54.7 GW of hydropower nameplate capacity (i.e., 54.1% of the U.S. total) resides in the WI, the primary focus region of this report.

[10] North American Electric Reliability Corporation, January 26, 2011, *Balancing and Frequency Control*. https://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[11] U.S. Energy Information Administration (EIA), 2019, "Form EIA-860 detailed data with previous form data (EIA-860A/860B)," September 3. https://www.eia.gov/electricity/data/eia860/.

[12] ORNL, undated, "HydroSource." https://hydrosource.ornl.gov/.

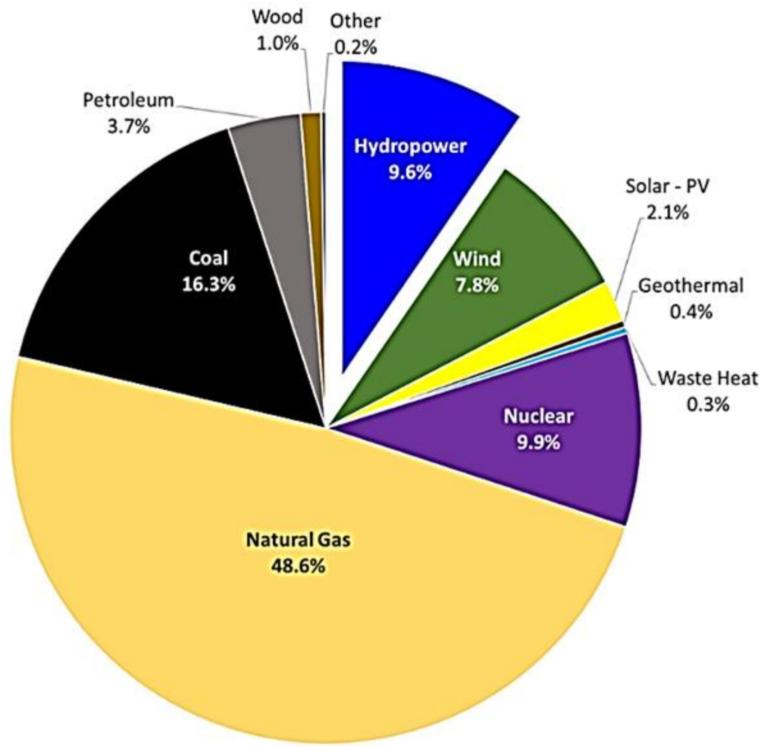


Figure 2-1 U.S. Nameplate Capacity Distribution by Technology in 2016

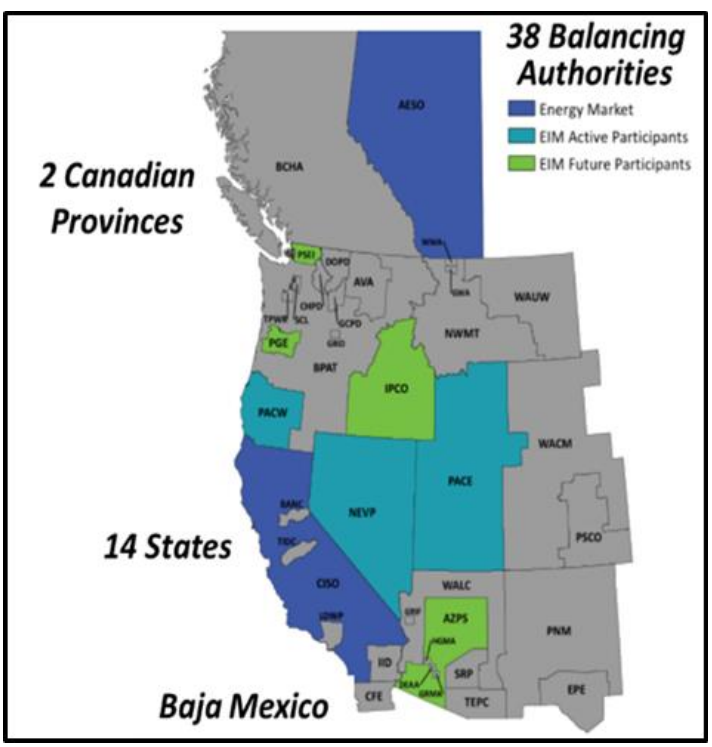


Figure 2-2 Western BA Interconnection

2.2 WI Nameplate Hydropower Capacity

WI covers the entire Western Electricity Coordinating Council (WECC) footprint. As shown in Figure 2-2[13], it includes all or parts of 2 Canadian provinces, 14 states in the United States, and Baja Mexico.[14] WECC contains a total of 38 active balancing authorities (BAs). However, this report focuses on the part of the WI that is in the United States.

The WI has a diverse mix of generating technologies, including large amounts of hydropower and other renewable resources. Along with coal, natural gas, and nuclear powerplants, the WI has a total combined generation capacity of roughly 265 GW. This accounts for approximately 20% of the capacity in the United States and Canada.

About 55 GW of the United States' hydropower nameplate capacity resides in the WI; that is, about 54% of the nation's total, of which almost three-fourths resides in the Bonneville Power Administration (BPA) BA and BAs that participate in the California Independent System Operator (CAISO) energy imbalance market (EIM). As shown in Figure 2-3, BPA accounts for 40% of the hydropower nameplate capacity of the WI. It is the main generation technology in terms of capacity in that BA, with a total capacity of almost 22 GW. Utilities that participate in the CAISO EIM represent the second largest amount of hydropower capacity, with a 33% share of the WI total. The vast majority of hydropower plants in the WI are intermediate peaking and peaking hydropower plants, which can store a certain amount of water in a small or large reservoir (Figure 2-4). ROR hydropower plants are much less prevalent. However, they represent at least 43% of the hydropower nameplate capacity of BPA.

[13] Based on map provided by WECC https://www.wecc.org/Administrative/Balancing_Authorities_JAN17.pdf.

[14] As approved by the Federal Energy Regulatory Commission (FERC), WECC is a nonprofit corporation that exists to assure a reliable bulk electric system in the geographic area known as the WI. NERC delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a delegation agreement.

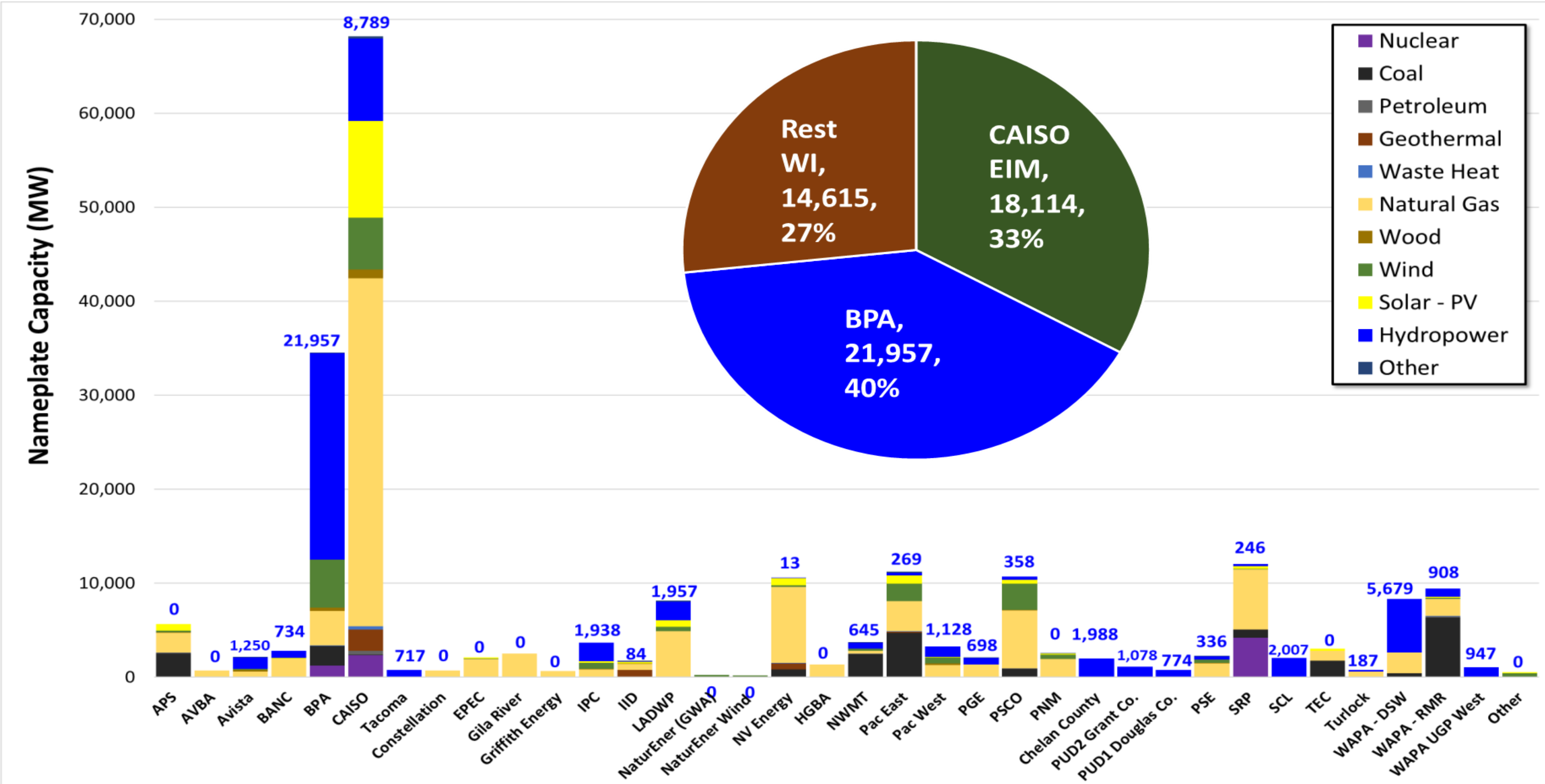


Figure 2-3 WI Hydropower Nameplate Capacity Shares and BA Primary Contribution by Energy Source[15]

[15] The Public Service Company of Colorado (PSCO) is now a subsidiary of Xcel Energy, Inc.

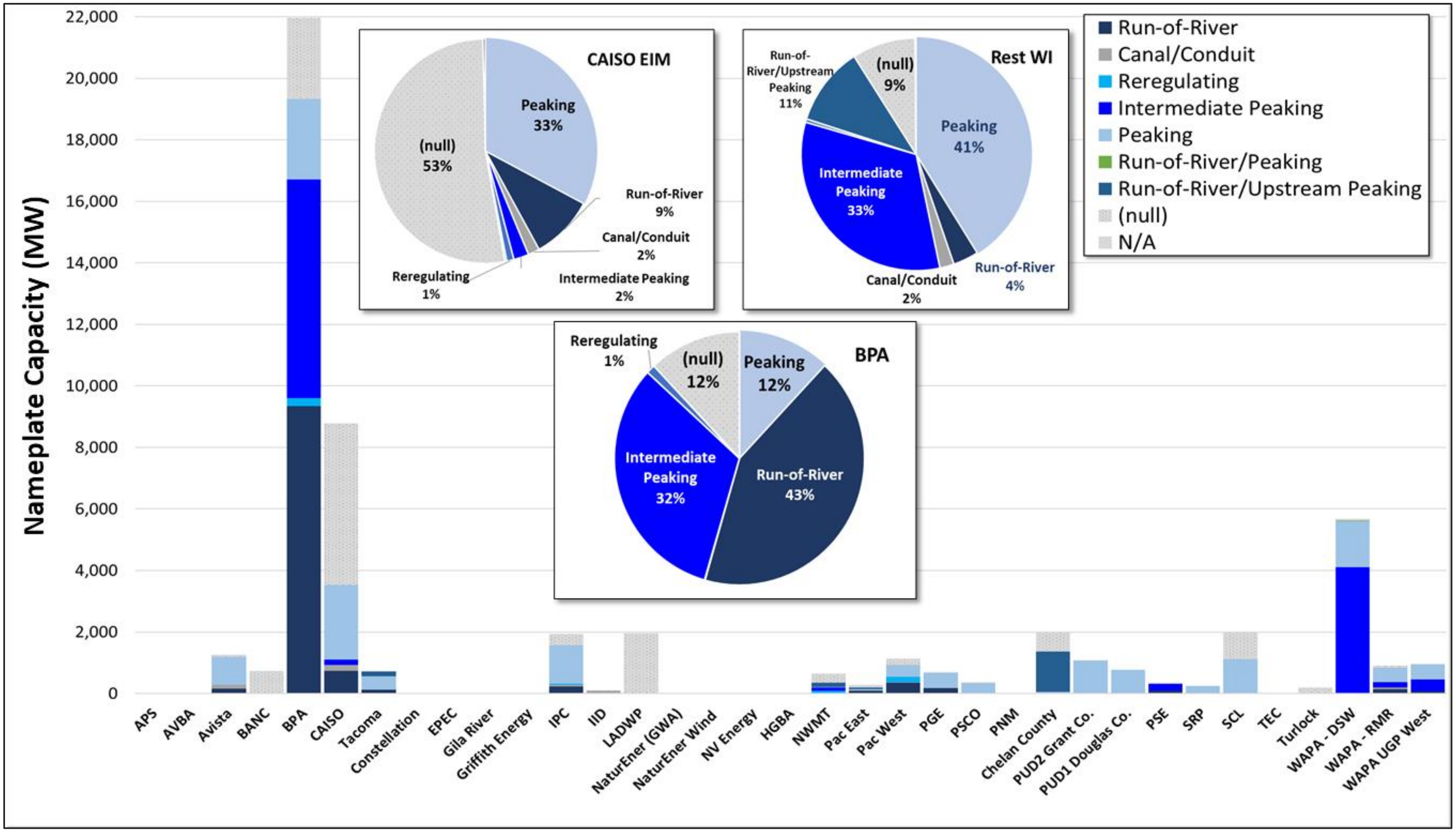


Figure 2-4 WI Hydropower Capacity by Type of Technology

2.3 Hydropower Firm Capacity Credit Value

The economic value of hydropower lies in its ability to lower system-level unit commitment and dispatch costs. In general, the economic value increases as a function of the plant capacity because a higher output potential allows the plant to utilize limited water resources for power production when the grid value of energy is high (e.g., during peak load hours). For the purpose of capacity value discussions in this document, however, capacity value is limited to the long-term economic value of a hydropower plant's firm capacity credit; that is, the cost savings associated with delaying/altering the expansion of power system resources due to the existence and operation of a hydropower resource. The level of firm capacity, and therefore its value, is based on the operational maximum output of a plant at the time of the system peak load. Under some situations the operational maximum may reach the maximum potential output; at the other extreme, it is possible for the operational maximum to equal zero if there is a total plant outage and/or the forebay elevation is below the minimum power pool level. Therefore, the firm capacity credit is also based on the risk preference of long-term system planners that trade system reliability for capacity expansion costs.

As illustrated in Figure 2-5, the firm capacity credit is typically lower than the nameplate capacity. Relative block sizes are specific to each hydropower plant and vary significantly by location due to many factors such as hydrological conditions, reservoir water storage capabilities, dam design, outage rates, the number of generating units at the plant, and environmental operating criteria. Plants with little or no storage, such as ROR hydropower plants, tend to have a lower firm capacity credit. On the other hand, plants associated with large reservoirs tend, in general, to be de-rated less by random and naturally occurring events. However, there are cases in which a ROR power plant has a relatively large firm capacity credit that is similar to its nameplate capacity while a large plant with an associated large reservoir could potentially have a zero firm capacity credit.

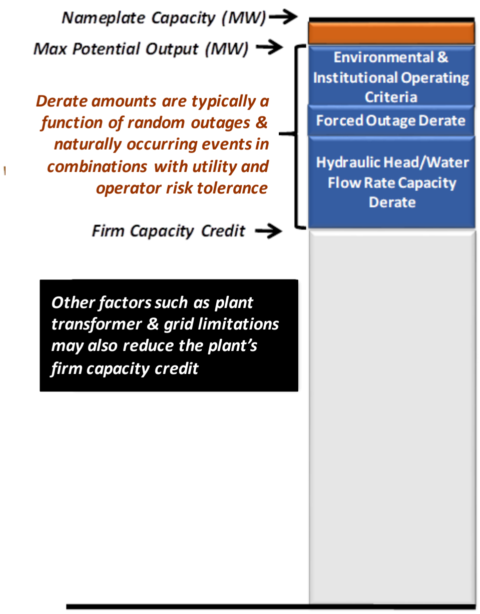


Figure 2-5 Firm Capacity Credit

2.4 Effects of Outages and Capacity De-rates on Firm Capacity Credits

Plant outages are major factors that affect a hydropower plant's firm capacity credit and therefore its economics. In a plant outage, units either are scheduled to be offline for maintenance or are forced out of service, usually because of a random event such as electrical system problems. Outages are typically not scheduled during peak load periods and therefore do not normally impact a hydropower plant's firm capacity credit. However, there is a chance that a random unscheduled outage, at the plant itself or at a transmission system/grid connection, will either totally or partially take either a unit or the entire plant offline when the system peak load occurs. According to Generating Availability Data System (GADS) statistics,[16] hydropower plants in the United States had an equivalent forced outage rate (EFOR) of 7.26% in 2017. Random outage frequency is significantly higher for units under 30 MW, with an average EFOR of 10.24%. Units greater than 30 MW which have an EFOR of 5.03%. Pumped storage hydropower plants have an average EFOR of 4.74%.

Figure 2-6 shows the average percent of offline capacity from 2000 to 2016 for a specific peaking hydropower plant in the WI. Monthly averages are shown in Figure 2-7. Note that the high runoff months of May and June and peak loads months of July and August have the smallest average monthly outages. During these months, plant owners/operators avoid scheduled outages to minimize lost generation opportunities due to non-power water releases. Avoiding scheduled outages during July and August also helps maximize the plants' firm capacity credit. In addition, the peak summer months tend to have the highest energy prices (i.e., highest marginal production cost), which allows plants to produce more energy during peak hours for the highest price. As reflected in Figure 2-7, units are scheduled for outages during periods of low inflows, typically during fall and winter, in order to reduce adverse financial/economic impacts.

The maximum potential output of a hydropower generating unit is based on the hydraulic head at the power plant. This is primarily a function of the reservoir forebay elevation, such that the maximum potential output increases as a function of hydraulic head, up to the maximum capability of the generating unit. Therefore, planners strive to have the reservoir full or nearly full during the time of peak load.

Reservoir elevation targets are also relatively high during these same months. For example, Figure 2-8 shows the average daily reservoir elevations at the Blue Mesa (BM) power plant and the associated average monthly elevation is shown in Figure 2-9. This pattern minimizes the hydropower capacity de-rate due to loss of hydraulic head during the peak load/price months of July and August, while at the same time increasing both the water-to-power conversion efficiency and the maximum potential output during this critical time period. Also note that the water elevation is drawn down from late summer to early spring to accommodate the storage of peak snow-melt periods that occur in May and June.

[16] NERC, 2017, "Generating Unit Statistical Brochures." https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.

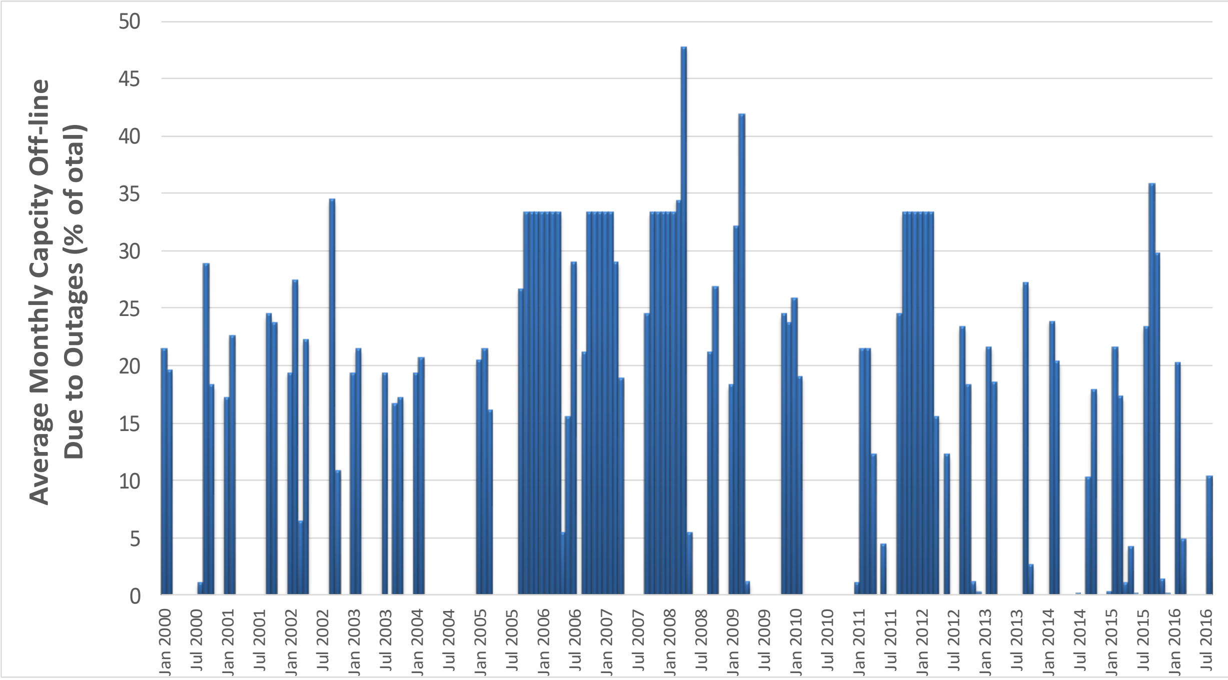


Figure 2-6 Percent of Capacity Offline for a Peaking Hydropower Plant in the WI

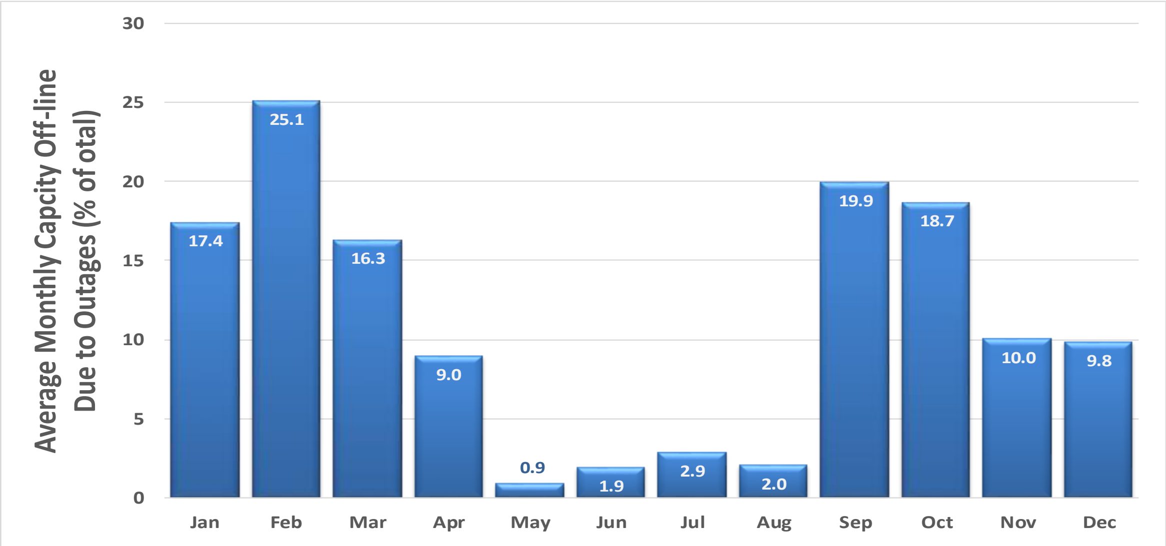


Figure 2-7 Average Monthly Outages during 2000–2016 in Terms of Percent Reduction of the Plants' Total Capacity

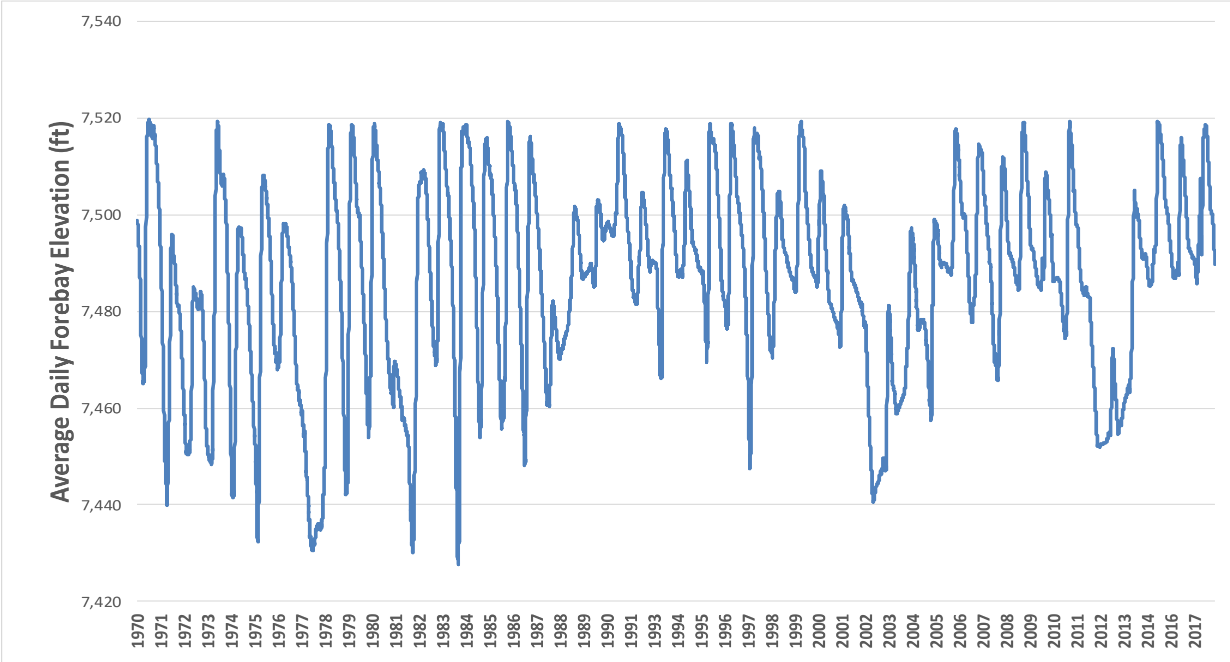


Figure 2-8 Average Daily Forebay Elevations at the BM Hydropower Plant

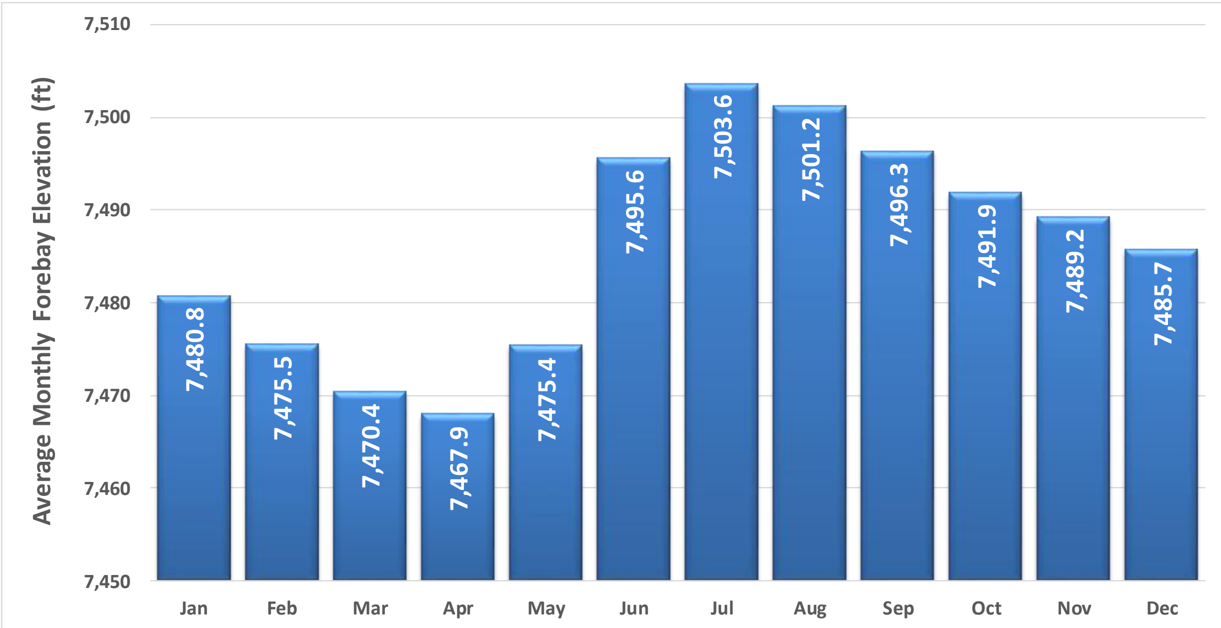


Figure 2-9 BM Hydropower Plant Average Monthly Forebay Elevations, 1970–2016

2.5 Effects of Environmental Operating Criteria on Firm Capacity Credits

Some hydropower plants are governed by environmental operating criteria that may constrain power plant operations. In general, these criteria restrict monthly, daily, and hourly operations by effectively constraining the temporal release of water, and therefore its generation pattern and economic value. Although these rules yield environmental benefits, they also have financial and economic implications. These operating criteria typically reduce the flexibility of operations, diminish dispatchers' ability to respond to market price signals, and lower the economic and financial benefits of power production.

Operational criteria affect hydropower economic value in two ways. First, hydropower energy cannot be used to its fullest extent during hours of peak electricity demand when the market price and economic benefits are relatively high. Second, there is typically a loss of firm capacity credit due to criteria that limit maximum output levels. As a result, this lost capacity must eventually be replaced by other power supply resources or the implementation of additional demand-side management (DSM) programs/initiatives.

Constraints may include, but are not limited to, reservoir water release rates and volumes, water flow rates/gauge heights at downstream locations, and both water temperature and water chemistry (i.e., dissolved oxygen level) below the hydropower plant. Long-term constraints may constrain monthly reservoir water release volumes, thereby reducing hydropower economic value by increasing releases during the springtime when the value of energy is relatively low. This draws down the reservoir elevation, which reduces the hydraulic head. This, in turn, de-rates the capacity of the unit(s) during peak summer load months. These higher environmental springtime water releases are typically supported by shifting water releases from months with higher energy value such as peak-load winter and summer periods.

Some constraints, such as those depicted in Figure 2-10, limit operations on shorter time scales. Operating criteria may restrict minimum and maximum release rates, the change in water release rate over time (e.g., hourly up- and down-ramping), and the maximum changes in water releases over a set period (e.g., range in flows over a rolling 24-hour period). Grid economic costs of implementing environmental operating criteria and/or conducting a special release is typically estimated via a comparative analysis. That is, grid economic values are computed under two cases: with and without environmental constraints. The difference in value is attributed to the environmental restrictions. Grid costs associated with environmental operating criteria are typically positive (i.e., incur compliance costs), but there are situations when grid costs are negative (i.e., they provide net economic benefits to the grid).

Comparative methodology is used not only to investigate grid impacts, but also to measure costs and benefits of environmental operating criteria for a range of subject areas to better inform decision makers about the pros and cons of changing reservoir and power plant operations. For example, studies conducted in support of environmental impact statements (EISs) investigate monetized and non-monetized costs and benefits on the macroeconomics of the impacted area, ecosystems, and society that are associated with changed water release patterns or volume that protect ecosystem services.[17]

[17] Bureau of Reclamation, 2016, "Glen Canyon Dam: Long-Term Experimental and Management Plan Environmental Impact Statement," U.S. Department of the Interior, October. http://ltempeis.anl.gov/documents/final-eis/Executive_Summary.pdf.

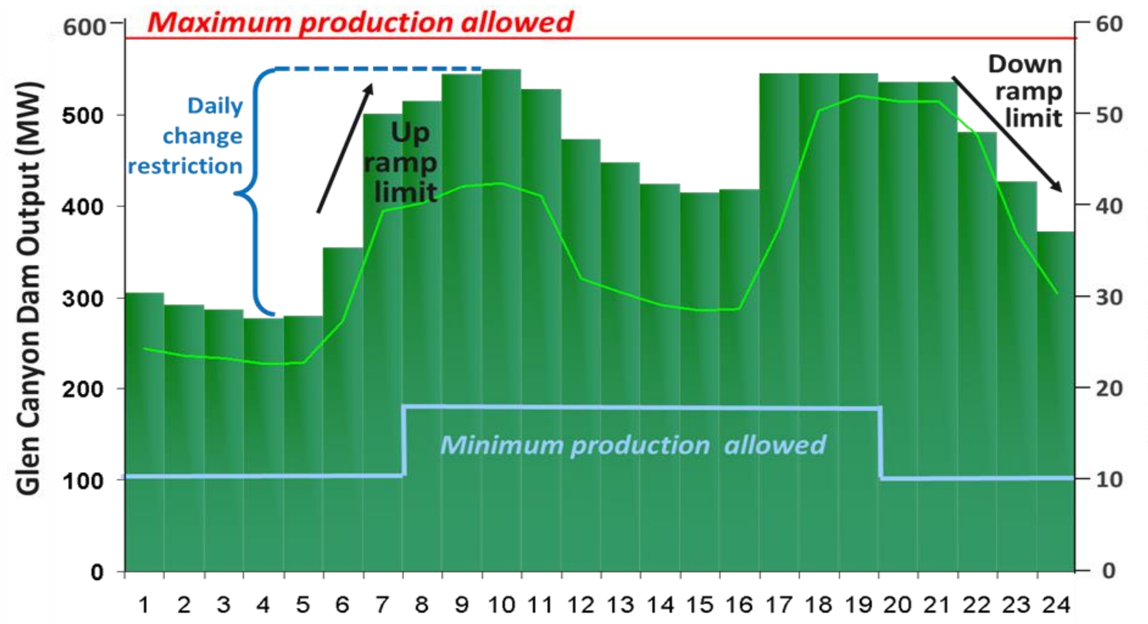


Figure 2-10 Effects of Environmental Operating Criteria on Hydropower Production Profiles and Economic Value

Studies have also shown that people derive benefits from free-flowing river water conditions.[18] Examples of potential benefits from implementing environmental constraints include recreational fishing and boating opportunities, protection of native species (and reduction of the risk that a species would become listed as threatened or endangered species), and improved health of riparian ecosystems.[19] Since the implementation of the Endangered Species Act of 1973, which seeks to protect endangered species from the negative effects of anthropogenic actions, some measures have been taken to reduce the environmental impacts caused by large human infrastructures, such as the impact of dams on aquatic species.

For example, at Glen Canyon Dam (GCD) there were fewer environmental restrictions prior to 1991. Table 2-1 shows that power plant water releases could range from 1,000 to 31,500 cfs, with no limit on daily fluctuations or ramp rate.[20] Such flexibility caused significant environmental damages, such as the disappearance of native fishes mainly due to changes in downstream water temperatures. From August 1991 to January 1997, temporary restrictions called "Interim Flow Restrictions" were put in place before the release of a final EIS. Since 1997, water releases have been reduced to a range from 5,000 to 25,000 cfs, and daily fluctuations and ramp rates have also been limited (Table 2-1). More recently, in January 2017, a new Record of Decision (ROD) mandating the preferred alternative prescribed by the Long-Term Experimental and Management Plan (LTEMP) EIS was adopted. It was first implemented in October of 2017.[21]

[18] D.A. Auerbach, D.B. Deisenroth, R.R. McShane, K.E. McCluney, and N. LeRoy Poff, 2014, "Beyond the concrete: Accounting for ecosystem services from free-flowing rivers," *Ecosystem Services* 10: 1–5, ISSN 2212-0416. https://doi.org/10.1016/j.ecoser.2014.07.005.

[19] H.I. Jager and B.T. Smith, 2008, "Sustainable reservoir operation: can we generate hydropower and preserve ecosystem values?" *River Res. Applic*. 24: 340–352. doi:10.1002/rra.1069

[20] Bureau of Reclamation, 1996, "Record of Decision, Operation of Glen Canyon Dam, Final Environmental Impact Statement, Appendix G," October.

[21] Bureau of Reclamation, 2016, "Glen Canyon Dam: Long-Term Experimental and Management Plan Environmental Impact Statement," U.S. Department of the Interior, October. http://ltempeis.anl.gov/documents/docs/LTEMP_ROD.pdf

Table 2-1 Evolution of GCD Operating Constraints

Operational Constraint	Historical Flows (before 1991)	1996 ROD Flows (from 1997 to 2017)	2016 ROD Flows (after 2017)
Minimum flows (cfs)	3,000 during the summer; 1,000 during the rest of the year	8,000 from 7:00 a.m. to 7:00 p.m.; 5,000 at night	8,000 from 7:00 a.m. to 7:00 p.m.; 5,000 at night
Maximum non-experimental flows (cfs)[a]	31,500	25,000	25,000
Daily fluctuations (cfs/24 hr)	28,500 during the summer; 30,500 during the rest of the year	5,000, 6,000, or 8,000 depending on release volume	Equal to 10× monthly water release (in TAF) during June–August, and equal to 9× monthly water release the rest of the year, but never exceeding 8,000 cfs
Ramp rate (cfs/hr)	Unrestricted	4,000 up; 1,500 down	4,000 up; 2,500 down

[a] Except during experimental releases.

Figure 2-11 shows the historical time series of the rated capacity (red line), monthly peak power output (red dots), and forebay elevation (blue line) at GCD. The three main operational periods are represented. During the period prior to environmental regulation (before 1991), GCD's maximum production was often higher than the rated capacity thanks to the windings used in previous turbines. Seven of the eight generating units were uprated between 1984 and 1987, and the last unit was uprated in 1997.[22] Currently, each of the eight generating units is rated at a capacity of 165 MW, for a total capacity of 1,320 MW.

The impact of the environmental constraints is clearly shown by the significant decrease of the monthly maximum power output from 1991 onward, despite an increase in the rated power capacity. Also note that the forebay elevation was on average at a lower level during the pre-environmental period.

Apart from the environmental restrictions, the GCD Adaptive Management Program, established by the GCD EIS ROD (Reclamation 1996), conducts scientific studies on the relationship between power plant operations and downstream resources. Experimental water releases are performed periodically to monitor river conditions, conduct specific studies, enhance native fish habitat, and conserve fine sediment in the Colorado River corridor in Grand Canyon National Park.

Between 1996 and 2016, seven high-flow experiments (HFEs) were conducted. These experiments were intended to mobilize the sand in the river with high-volume water releases from the dam and redeposit it downstream as sandbars along the Colorado River. The seven HFEs were conducted in March 1996, November 2004, March 2008, November 2012, November 2013, November 2014, and November 2016.[23] Part of the water is released through bypass, while another part is released through the generating turbines, which produces relatively high levels of power. The six first HFEs are identified in Figure 2-11 by the green circles circling some of the red dots. Peak generation during these experiments are relatively high than during other months.

[22] Source: https://web.archive.org/web/20150905122942/ http://www.usbr.gov/projects/Powerplant.jsp?fac_Name=Glen%20Canyon%20Powerplant

[23] U.S. Geological Survey, undated, "High-Flow Experiments on the Colorado River," U.S. Department of the Interior. https://www.gcmrc.gov/high_flow/high_flow_default.aspx.

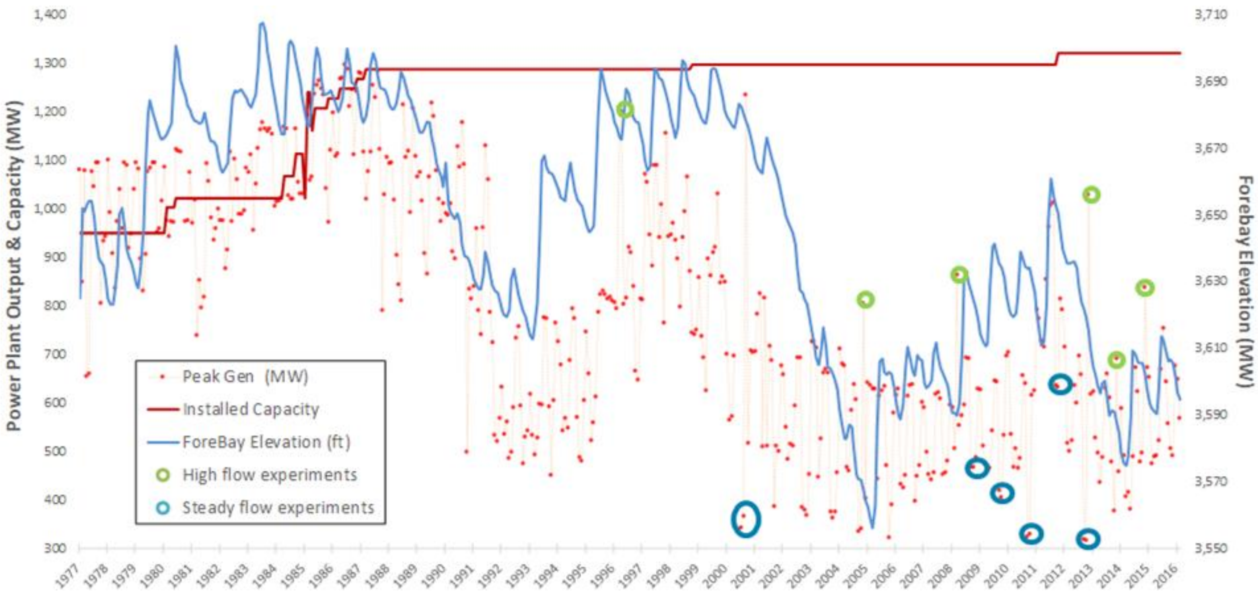


Figure 2-11 Evolution of Rated Capacity, Monthly Peak Power Output, and Forebay Elevation at GCD

Apart from the HFEs, six steady flow (SF) experiments have also been conducted at GCD. One low summer SF (LSSF) was conducted from the end of May through the beginning of September 2000, and five fall SF (FSF) experiments were conducted during the months of September and October of 2008–2012. The goal of these experiments was to understand how river discharge could influence the growth, survival rates, and habitat use of juvenile native fish in the Colorado River in Grand Canyon.[24] Low reservoir water releases were maintained during these periods and, as a result, peak generation was also relatively low, as shown by the blue circle in Figure 2-11.

The new restrictions from 1996 ROD also had a clear impact on the hourly water flow fluctuations. Figure 2-12 compares the hourly turbine water release at GCD and water flow at Lee's Ferry between 1987 and 2015 during the week of July 19 to July 25. The gauge at Lee's Ferry measures stream's water-flow rate and is located 16 miles downstream from GCD. Because of its proximity to GCD, the variation and magnitude of water flows at Lee's Ferry closely follow those of GCD water release. New environmental restrictions mandated in 1997, especially the daily fluctuation constraint, significantly reduced the intensity of the water flow fluctuations at the gauge and, consequently, lowered the negative impacts of rapidly fluctuating flows on downstream aquatic life.

Because water flow rate and power are closely related, power capability at GCD has also been significantly reduced (Figure 2-13). Before the environmental restrictions, during the week from July 19 to July 25, 1987, GCD was able to produce a peak of power of 1,164 MW, that is, 90% of the rated capacity of this period. After the 1996 ROD, during the same week in 2015, this peak generation dropped to 746 MW, that is, only 56% of its current nameplate capacity. As a result of operating criteria that reduce the peak output of the plant, the plant de-rated capacity has increased.

[24] Glen Canyon Dam Adaptive Management Program Wiki, 2019, "The 2000 Low Summer Steady Flow Experiment," accessed [3/6/2020]. http://gcdamp.com/index.php?title=The_2000_Low_Summer_Steady_Flow_Experiment

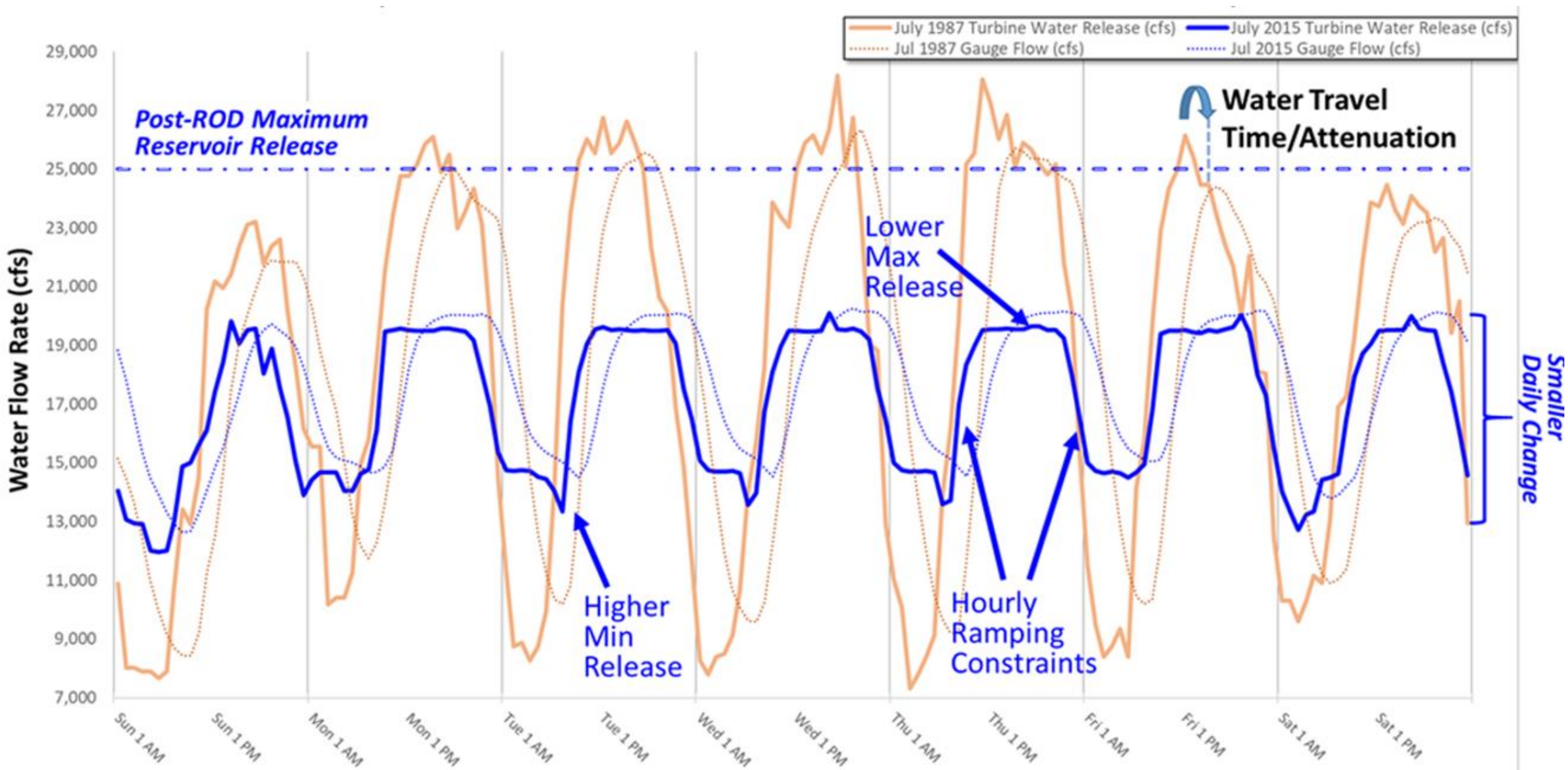


Figure 2-12 GCD's Turbine Release and Lee's Ferry's Flow Rate Profiles during the Same Week in 1987 and 2015

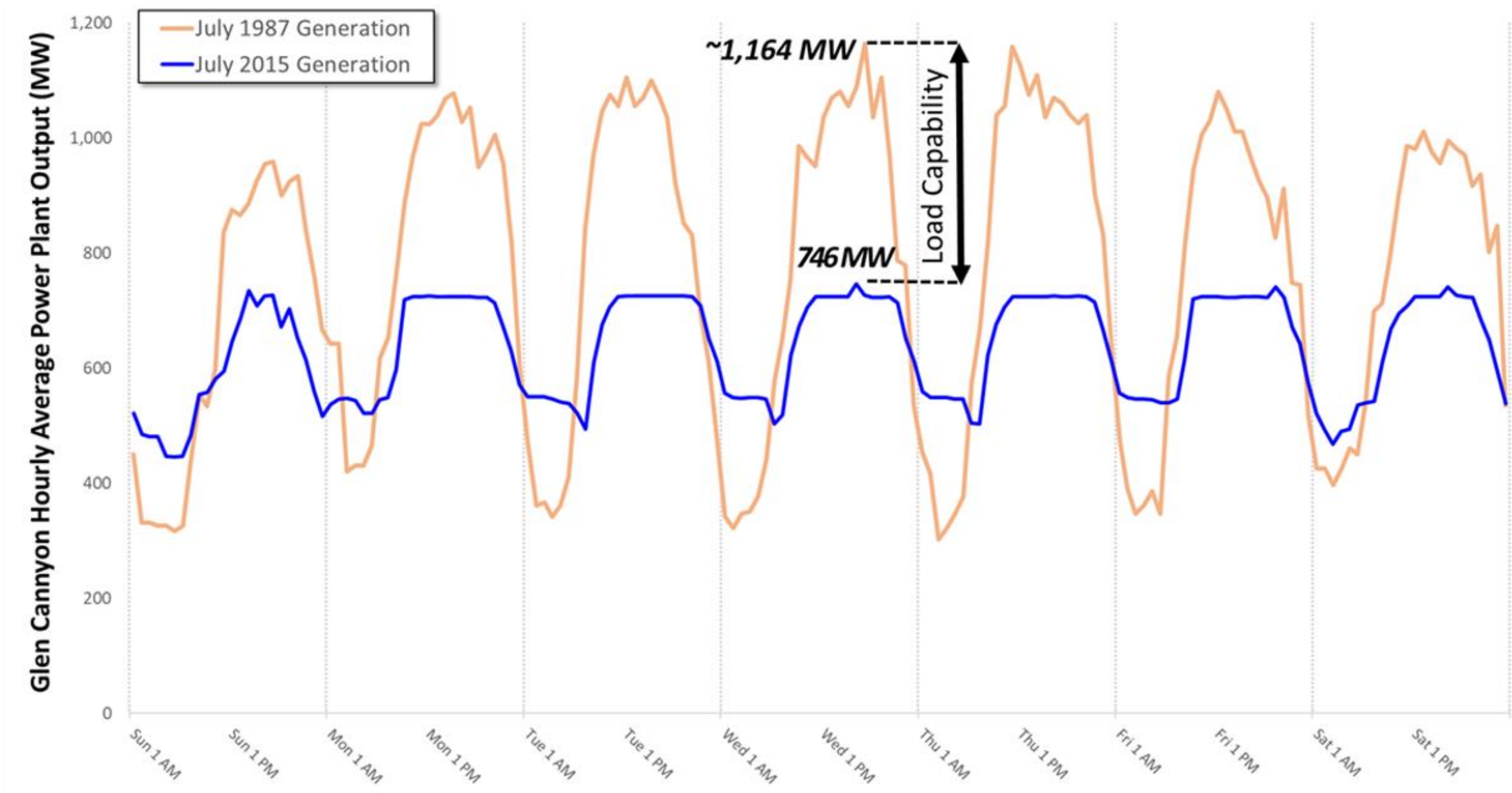


Figure 2-13 GCD's Generation Profile during the Same Week in 1987 and 2015

2.6 Probabilistic Determination of the Firm Capacity Credit

There is no single criteria for determining the firm capacity credit of a hydropower plant; that is, the amount of capacity that is used when computing capacity RMs in an IRP. Various government agencies and private owners choose different criteria to define firm hydropower capacity. For example, the firm capacity of hydropower resources in the Western Area Power Administration's (WAPA's) Colorado River Storage Project (CRSP) is based on an adverse hydropower level, defined as 90% exceedance level, and the nameplate capacity. The choice of criteria depends on CRSP management. On the other hand, the BPA defines capacity by average megawatts and Pacific Gas and Electric defines the capacity of its small- and medium-sized units based on adverse water conditions. Many private owners use nameplate. For illustrative purposes, this section uses the 90th percentile exceedance level to define firm capacity credit.

The firm capacity credit given to a plant has economic value because construction cost for a replacement power plant with equal characteristics is averted. Of course, this presumes that construction costs are the same as market value and that market value is the same as social value. These assumptions are valid under conditions of fair, competitive markets.

Because of the variability and the associated uncertainty of conditions that drive the operational maximum level, the firm capacity credit of a hydropower plant is typically based on the probability that the projected energy production level will be at the firm capacity level or higher during time of the system peak. This probability level is set by the utility that conducts the IRP as reflected in its risk tolerance level. Figure 2-14 illustrates a hydropower plant's firm capacity credit, which is typically, but not always, significantly less than its highest operational maximum. The shape of the exceedance curve is highly dependent on the characteristics of the hydropower plants, reservoir waters storage characteristics, plant/reservoir operating criteria, the month/season when the peak load occurs, and basin/sub-basin hydrological profiles.

For a hydropower plant, the firm capacity level assigned to it depends on the risk tolerance of the utility that is conducting the IRP. A higher risk tolerance yields to a higher firm capacity, while a lower risk tolerance will result in a lower firm capacity. In Figure 2-14, the firm capacity credit, which is based on a risk tolerance of 10% (i.e., the 90% hydropower exceedance level), is 700 MW. Using a 90% exceedance level means that at least 700 MW of operational capacity would be available 9 out of 10 times. At a higher risk-tolerance level of 50%, the firm capacity credit is much higher at 950 MW, but the utility would not be able to attain this power output level half of the time.

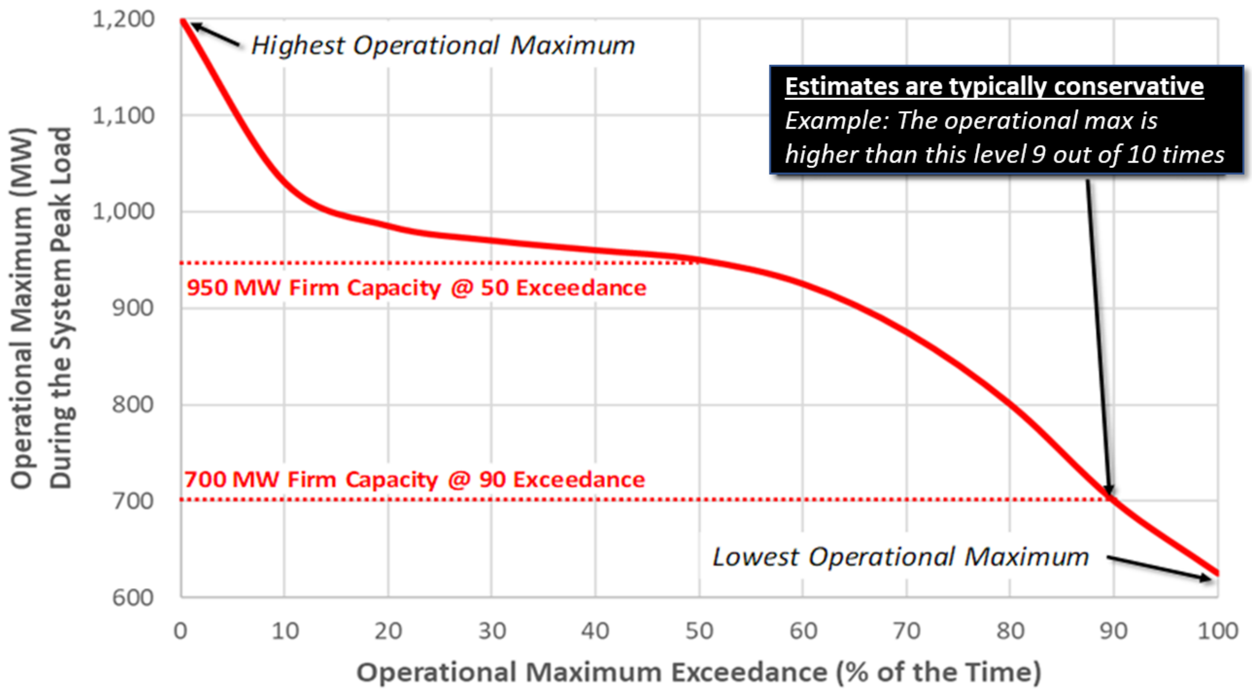


Figure 2-14 Risk-based Firm Capacity Credit Approach

The firm capacity credit of a ROR hydropower plant is often much lower than its nameplate capacity and/or maximum potential output. For example, Figure 2-15 shows a production exceedance curve for the Ice Harbor ROR hydropower plant located on the Snake River in Burbank, Washington. It is based on the plant's historical daily peak production level during the weekdays of the month of peak demand. Assuming a 90% exceedance level, the plant's summer firm capacity is about 11% of its nameplate capacity of 603 MW. The percentage is even lower when compared to the historical maximum output of 641.2 MW (presumably the plant's maximum potential output). The firm capacity is much higher during the winter because there are higher flows during that time of year. The WI is, however, a summer peaking system, and therefore the relatively low summer firm capacity would be used for an IRP. Because almost 30% of U.S. hydropower capacity comes from ROR hydropower plants, the nationwide hydropower firm capacity is, overall, much lower than its nameplate capacity.

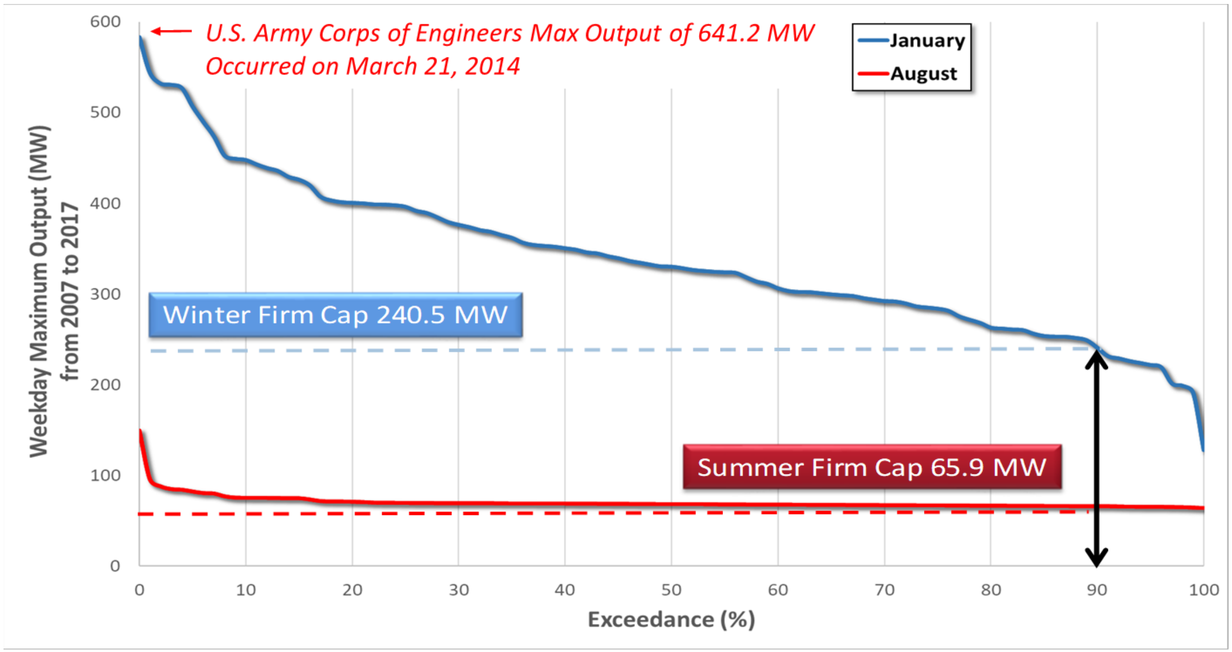


Figure 2-15 Firm Capacity Credit for the ROR Ice Harbor Power Plant (nameplate capacity: 603 MW)

Using historical data to determine firm capacity credits for ROR hydropower plants implicitly includes all of those “block” elements shown in Figure 2-5 that affect the plants’ operating capability; that is, the blocks that are between maximum potential output and the firm capacity credit. Because ROR power plants do not provide either operating or contingency reserves, it is also a good measure of the operational maximum.

The firm capacity is typically closer to its nameplate for peaking hydropower plants that have large water storage reservoirs. This is because a large water storage capacity allows hydropower plant planners/schedulers to shift monthly water discharges, and therefore generation, from months with high reservoir inflows that have lower marginal energy costs (e.g., spring) to months with lower inflows that have higher value (summer). Water storage enables not only higher summertime water releases, but also increased water-to-power conversion efficiencies as a result of an elevated forebay.

The shape of the power exceedance curve and, therefore, the firm capacity level for a peaking hydropower plant influences the management of water storage facilities in the basin. Storage hydropower plants therefore tend to have a firm capacity credit that, relative to ROR hydropower plants, is closer to the maximum potential output during the critical annual peak load period. Moreover, the larger the reservoir, the greater the level of water availability, and the smaller the gap between its nameplate capacity and firm capacity credit. Figure 2-16 illustrates the firm capacity credit for the peaking hydropower plant Priest Rapids, located on the Columbia River. Note that the summer firm capacity credit is about 60% of the nameplate capacity, as compared to only 11% of the nameplate capacity for the ROR plant.

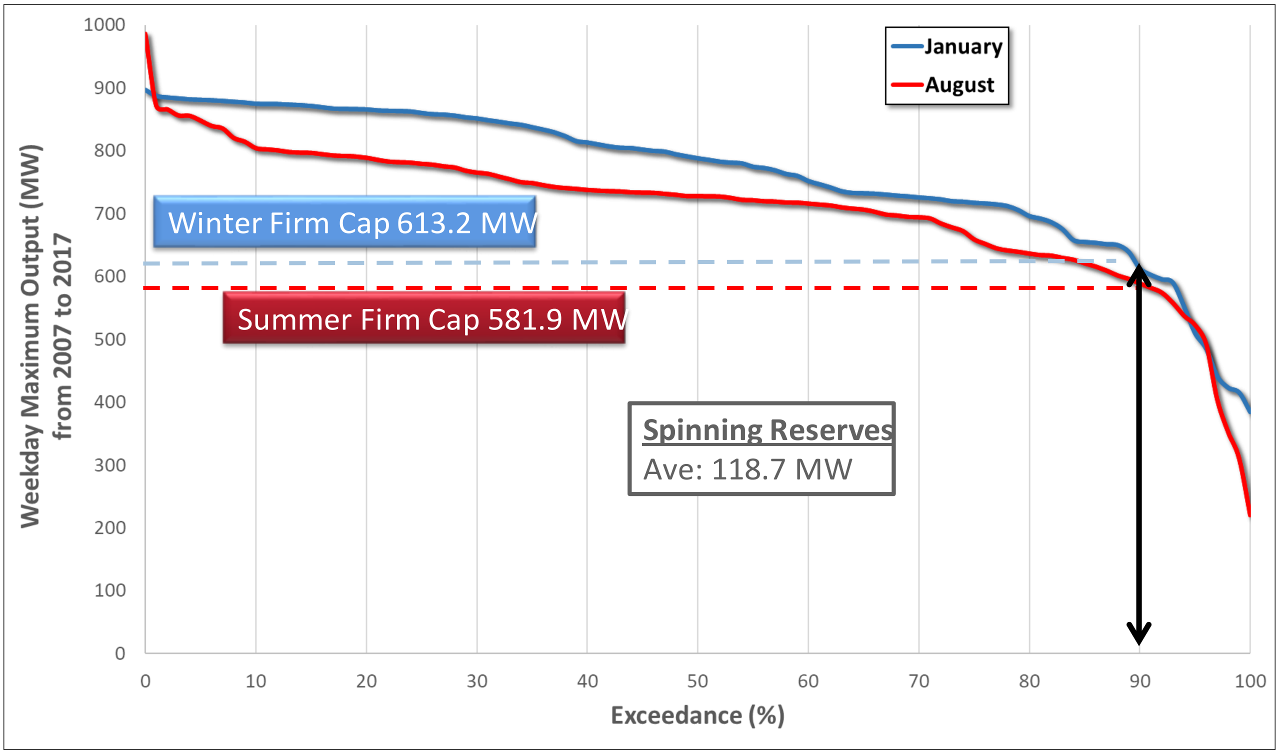


Figure 2-16 Firm Capacity Credit for the Priest Rapids Peaking Plant (nameplate capacity: 955.6 MW)

However, there are exceptions. For example, in a region undergoing an extended drought (e.g., a drought lasting several years) in combination with inflow forecast error and/or statutory downstream water delivery obligations, a storage plant may have a zero-firm capacity. This typically occurs when there is a summertime risk (e.g., 10% or more) of the water elevation dropping below the minimum power-pool level. Below this minimum forebay elevation, the plant would not be able to produce power.

2.7 Hydropower Capacity Value from the RM Standpoint

The relative difference between the firm capacity credit and the nameplate capacity tends to decrease when the simultaneous production of several hydropower plants is combined into a coordinated group. In other words, the firm capacity credit of a set of hydropower plants combined together is generally greater than the sum of the individual firm capacity credits. This is due to the diversity of the inflow profiles among the hydropower plants during low hydropower conditions.

Figure 2-17 illustrates the individual exceedance probability curve of several ROR hydropower plants in CAISO, the sum of the individual exceedance probability curves (green line), and the exceedance probability curve of the combined set of hydropower plants (red line). When considering the hydropower plants together (red line), the lowest combined generation capacity available 43% of the time or less (between 57% and 100% exceedance) is actually greater than the sum of individual generation capacities available for the same proportion of time (green line). Moreover, the lowest possible generation capability available for the combined group (i.e., at 100% exceedance) is 10 times larger than the sum of the individual lowest generation capacities available.

Based on August Monthly Data

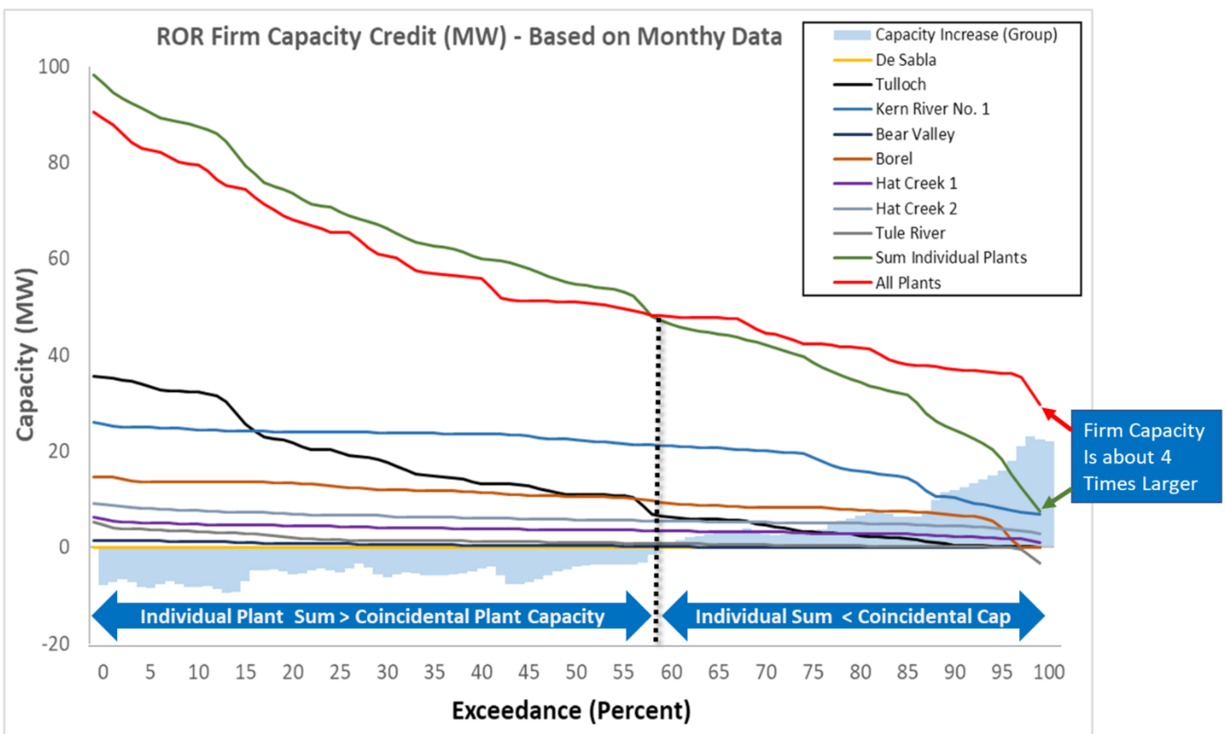


Figure 2-17 Firm Capacity Credit of Several ROR Hydropower Plants in CAISO

This implies that a region composed of several hydropower plants with diverse hydrological profiles has a higher firm capacity credit and, therefore, requires less generation capacity expansion to meet its RM. Moreover, from an operational point of view, the hydropower generation profile of such a region is less volatile.

To take advantage of hydropower diversity among plants that are located far apart, there must be a transmission network that links geographically dispersed facilities together. Transmission lines must also have sufficient capacity to enable power transfers across the interconnection. If hydropower plants are owned by different entities, resource diversity benefits are only realized when there is cooperation and coordination among hydropower owners and utilities. In some situations there may be institutional barriers, which either directly or indirectly limit bulk power exchange the “shared” use of firm capacity.

An operational maximum exceedance curve may be based on historical power plant generation data, as illustrated in the examples above. However, both natural and power systems evolve often, making it necessary to perform computer simulations that project a range of plant operations under an ensemble of future potential hydrological conditions. Furthermore, the exceedance curve should ideally be based on *future* conditions, at the time when a new resource would need to be constructed in order for the utility/system to remain either at or slightly above a target system RM. This future exceedance curve may differ significantly from a curve that is constructed for the historical operations because the *current* state of basin reservoirs and future basin policies/regulation may have an excessive influence over both the magnitude and shape of the curve.

Depending on the current RM of the system, system load growth projections, and the retirement schedule of existing resources, the need for additional resources may be within either the next year, a decade, or more. Anticipated changes in hydrological/inflow conditions at the hydropower plant and equipment upgrades or degradation of plant components may significantly impact the future operational maximum output. For example, increases in basin water withdrawals upstream of a hydropower resource could have significant impacts on water resources at the plant, thereby reducing its maximum potential output. On the other hand, a warmer climate could potentially result in higher precipitation levels and/or increased glacier melt over the next few decades resulting in higher production levels.

Modeled futures are required when there is insufficient historical data to support the construction of an exceedance curve or hydropower plant attributes and/or water availability are anticipated to change in the future. Changes that may occur in the future include, but are not limited to, evolving hydrological conditions as a result of climate changes, increased withdrawals of water within the basin/sub-basin, interbasin water diversions, and the construction of an upstream reservoir(s).

The value of a hydropower plant is related to its firm capacity credit level and the extent to which this capacity impacts the construction of new supply resources in the grid. Capacity value therefore depends not only on the power plant itself, but also the load and resource mix of the power system in which it resides. Using the logic embedded in the avoided-cost methodology, the economic value of a hydropower plant can be estimated via the examination of a counterfactual case in which the plant is “removed” from the grid. Without the existence of a specific hydropower plant, new supply resources would eventually be constructed to replace it. The retirement would accelerate the capacity expansion schedule and therefore both capital expenses and fixed operation and maintenance (O&M) costs. The removal of a plant would also impact the dispatch and therefore system production costs.

Figure 2-18 illustrates the time when future new resources need to be brought online to meet a RM target. In order to have enough capacity online to meet a minimum RM target, new resources would need to be built sooner if a hydropower plant and its associated firm capacity are not available (counter-factual case). Online firm capacity (black solid line) needs to be higher than the forecasted annual peak load (green line) plus a minimum RM target to reliably meet demand. Capacity reserves are needed because future load projections may be higher than previously forecasted and the “spare” capacity is needed to replace generation during outage events that may potentially coincide with the timing of the peak load. Note that not only does new capacity come online sooner without hydropower capacity, but a higher amount of expansion capacity is needed indefinitely (thick gray vertical arrows).

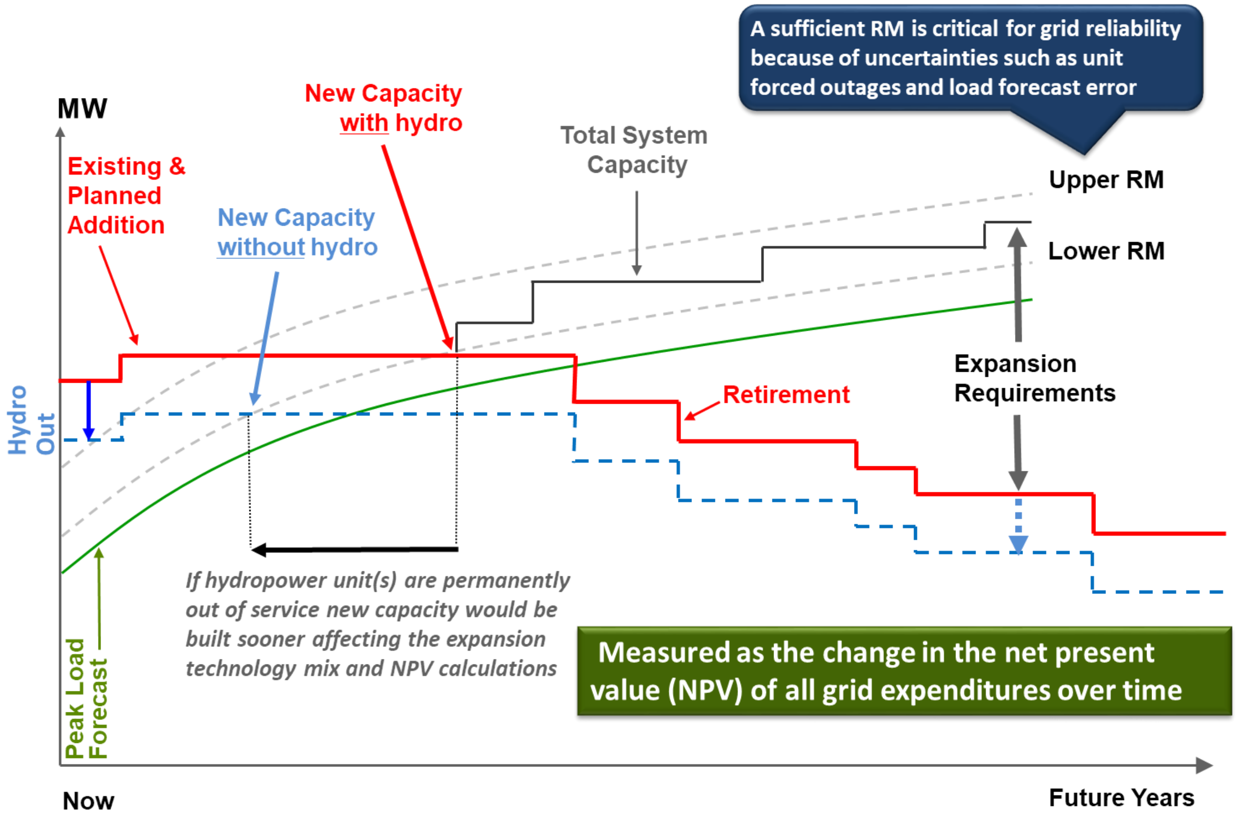


Figure 2-18 Removal of a Hydropower Plant Accelerates the IRP Construction Schedule

Because units come online sooner when a hydropower plant is removed from the system, both capital expenditures and fixed O&M expenditures occur sooner. The cost of replacement capacity is therefore dependent on both the timing of the replacement and the assumed time value of money (discount rate) that is used to compute the net present value (NPV) of a time series of all capacity expansion expenditures. These expenditures include, but are not limited to, planning and compliance costs, allowances for funds during construction (AFUDCs), capital expenses, and, once the plant comes online, fixed O&M costs. Additional costs may also include transmission and grid connection costs.

Furthermore, note that unit additions come online in "blocks" of capacity. It therefore creates temporary excess capacity that is above the minimum RM target. Because the behavior of the total amount of online capacity is lumpy, it is important to evaluate the entire time series of capacity expansion additions over the lifetime of the replacement capacity.

In the WI, there are currently sufficient firm capacity resources to reliably meet peak loads in the four NERC subregions shown in Figure 2-19.[25] NERC is a nonprofit corporation whose main responsibility is to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America. As shown in Figure 2-20, capacity RMs computed by each individual WECC region of NERC are well above the reference RM that NERC deems to be sufficient from a reliability perspective in two of the four subregions though the year 2028. It is not until the end of this period that the Rocky Mountain Reserve Group (RMRG) and the Southwest Reserve Sharing Group (SRSG) subregions dip slightly below the reference RM. With sufficient transmission capability, additional firm contractual arrangements among the subregions could potentially resolve the small 2027 and 2028 capacity shortfalls in RMRG and SRSG.

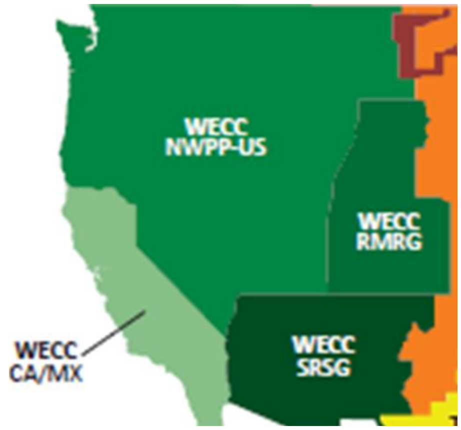


Figure 2-19 NERC Subregions in the WI

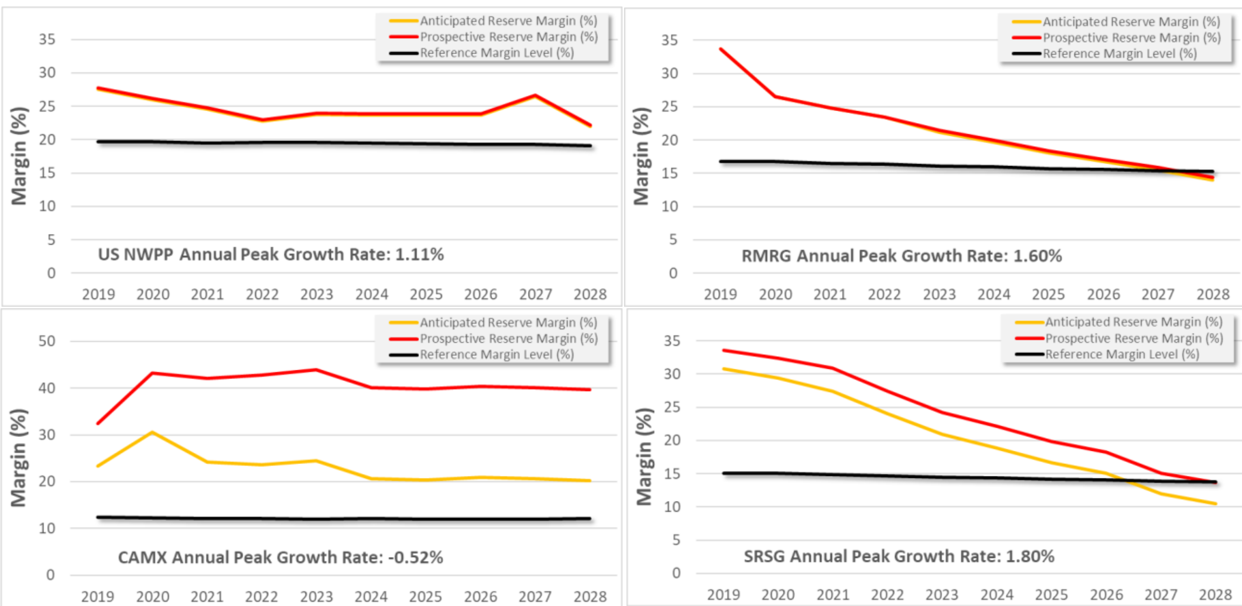


Figure 2-20 Capacity RMs in the Four NERC Subregions, 2019–2028

This situation of excess capacity significantly reduces the economic values of hydropower capacity in the WI because if a single hydropower unit is taken offline indefinitely (i.e., retired) then, from a strict RM perspective, the "lost" capacity would not be replaced for at least a decade or more. Because of the time-value of money, any replacement capacity expenditures would be significantly discounted to the present. On the other hand, if many hydropower units (e.g., all of them) were to retire, this would have a major impact on RMs dipping to negative in several BAs. Therefore, in the WI, the aggregated capacity of all hydropower assets has a high value.

[25] North American Electric Reliability Corporation, "Assessment Areas (as of July 2010)", https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Assessment%20Areas.jpg

It should be pointed out that, in the WI, especially in the California–Mexico (CAMX) subregion, the RM should not be the sole measure of reliability. The trends in CAMX highlight how important it is for industry to evaluate the ability of the resource mix to adequately meet net-load (load minus VER production) ramping needs as more VERs are added to its footprint. Ramping needs are the largest during the off-peak months of the year, typically during low-load conditions in the spring and fall. If there is insufficient flexibility in the system, then loads cannot be fully served. Therefore, in footprints with a large penetration of VERs, even in situations of excess capacity, the capacity of highly flexible hydropower plants will continue to have economic value because if hydropower plants are taken offline, new replacement capacity with fast ramping capabilities may need to be constructed to replace the lost capacity.[26]

A projection of future system RMs and other system requirements, such as flexible ramping requirements that ensure system reliability, provides information about when lost hydropower capacity would need to be replaced. However, it does not provide information about what type of replacement capacity should be built. The type of replacement is important because both investment costs and fixed O&M costs vary widely by technology type, significantly affecting the estimate of the capacity replacement costs and hence economic value. In addition, once a replacement capacity is constructed, its inclusion in the system dispatch impacts system production costs and system reliability. Table 2-2 shows the cost and performance characteristics of new central station electricity generating technologies.[27]

One methodology for determining the capacity replacement technology is to simply look at the types of new capacity that are being constructed in the region and assume that the replacement capacity would be similar to the types of technologies that are being constructed and/or are planned to be constructed within the next few years. Using this methodology, the replacement capacity in the WI would most likely either be a natural gas-fired or VER technology. This is based on data found in Figure 2-21 that illustrates Tier 1 future capacity supply additions in North America as reported in the NERC "2018 Long-term Reliability Assessment."[28] These future additions include resources that are newly built but not yet in operation, as well as those that are under construction. They also include various signed and approved agreements and technologies included in either IRPs or mandated resource adequacy plans. Figure 2-22 shows combined Tier 1 and Tier 2 supply additions. Tier 2 resources include those in various signed/approved studies, requested interconnection service agreements, and IRPs or resource adequacy requirements. Last, as shown in Table 2-3, several utility IRPs in the WI primarily include natural gas, combined cycle, and renewable (both wind and solar) technologies.

[26] North American Electric Reliability Corporation, 2018, "2018 Long-Term Reliability Assessment," December. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

[27] U.S. Energy Information Administration, 2020, "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook, 2020," January, https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

[28] North American Electric Reliability Corporation, 2018, "2018 Long-Term Reliability Assessment," December. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

Table 2-2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2019$/kW)	Technological optimism factor[c]	Total overnight cost[d,e] (2019$/kW)	Variable O&M[f] (2019$/MWh)	Fixed O&M (2019$/kW-yr)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2023	650	4	3,661	1.00	3,661	4.48	40.41	8,638
USC with 30% carbon capture and sequestration (CCS)	2023	650	4	4,539	1.03	4,652	7.05	54.07	9,751
USC with 90% CCS	2023	650	4	5,851	1.03	5,997	10.93	59.29	12,507
Combined-cycle—single shaft	2022	418	3	1,079	1.00	1,079	2.54	14.04	6,431
Combined-cycle—multi shaft	2022	1,083	3	954	1.00	954	1.86	12.15	6,370
Combined-cycle with 90% CCS	2022	377	3	2,470	1.04	2,569	5.82	27.48	7,124
Internal combustion engine	2021	21	2	1,802	1.00	1,802	5.67	35.01	8,295
Combustion turbine—aeroderivative[h]	2021	105	2	1,170	1.00	1,170	4.68	16.23	9,124
Combustion turbine—industrial frame	2021	237	2	710	1.00	710	4.48	6.97	9,905
Fuel cells	2022	10	3	6,671	1.10	7,339	0.59	30.65	6,469
Advanced nuclear	2025	2,156	6	6,016	1.05	6,317	2.36	121.13	10,461
Distributed generation—base	2022	2	3	1,555	1.00	1,555	8.57	19.28	8,946
Distributed generation—peak	2021	1	2	1,868	1.00	1,868	8.57	19.28	9,934
Battery storage	2020	50	1	1,383	1.00	1,383	0.00	24.70	NA
Biomass	2023	50	4	4,080	1.01	4,104	4.81	125.19	13,500
Geothermal[i,j]	2023	50	4	2,680	1.00	2,680	1.16	113.29	9,156
Municipal solid waste—landfill gas	2022	36	3	1,557	1.00	1,557	6.17	20.02	8,513
Conventional hydropower[j]	2023	100	4	2,752	1.00	2,752	1.39	41.63	NA
Wind[e]	2022	200	3	1,319	1.00	1,319	0.00	26.22	NA
Wind offshore[i]	2023	400	4	4,356	1.25	5,446	0.00	109.54	NA
Solar thermal[i]	2022	115	3	7,191	1.00	7,191	0.00	85.03	NA
Solar photovoltaic—tracking[e,i,k]	2021	150	2	1,331	1.00	1,331	0.00	15.19	NA

(Table notes appear on the next page.)

[a] Represents the first year in which a new unit could become operational.
[b] Base cost includes project contingency costs.
[c] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[d] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2020.
[e] Wind and solar PV technologies' total overnight cost in the table shows the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2018 in each region to account for the substantial regional variation in wind and solar costs. The input value used for onshore wind in AEO2020 was $1,260 per kilowatt (kW); for solar PV with tracking it was $1,307/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs through the country.
[f] O&M = Operations and maintenance.
[g] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to- storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit conversion factors exist. The model calculates the average heat rate for fossil generation in each year to report primary energy consumption displaced for these resources.
[h] Combustion turbine aeroderivative units can be built by the model before 2021, if necessary, to meet a region's reserve margin.
[i] Capital costs are shown before investment tax credits are applied.
[j] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and Great Basin region for geothermal, where most of the proposed sites are located.
[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
Sources: Input costs are primarily based on a report provided by external consultants: Sargent & Lundy, December 2019. Hydropower site costs for non-powered dams were most recently updated for AEO2018 using data from Oak Ridge National Laboratory.

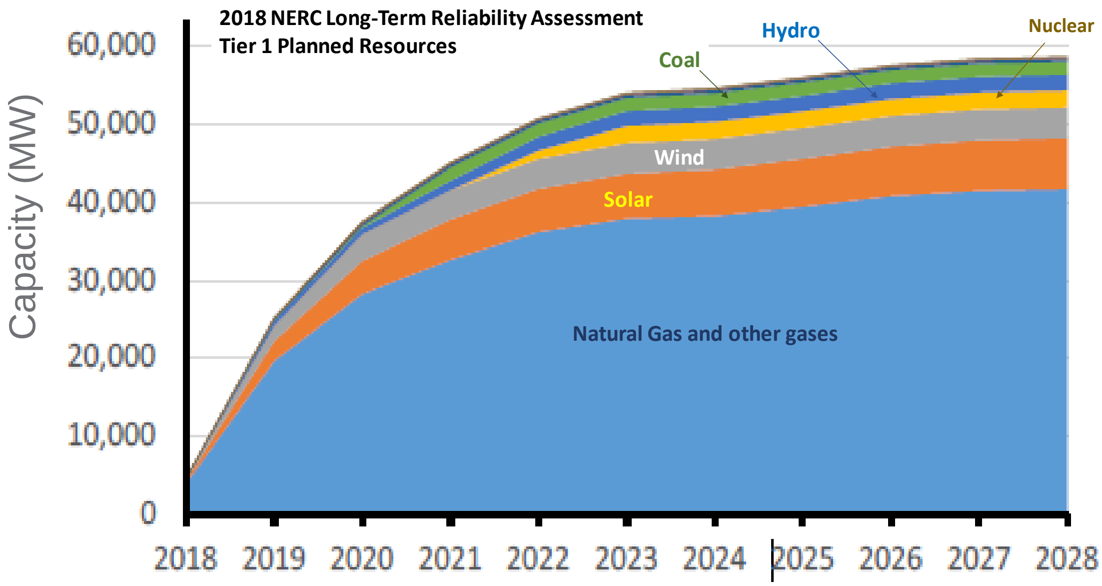


Figure 2-21 NERC North America Tier 1 Future Supply Resource Additions

If no replacement capacity is required for several more years, or if the grid is evolving rapidly, current replacement trends and near-term plans may not be adequate. Another more detailed method for evaluating the economic cost of hydropower capacity is to use a capacity expansion model to estimate when, where, and what type of capacity should be constructed in the future. Expansion models also use cost algorithms that evaluate the impact of capacity expansion pathways on grid economics. When using a capacity expansion model, lost capacity is typically evaluated through a comparative analysis that examines interconnection NPV difference between a status quo case (i.e., with hydropower) and a change case (i.e., without hydropower or with reduced hydropower capacity). The NPV calculation includes dispatch costs, fixed O&M costs, capital investment costs for the construction of new capacity, and production costs over time.

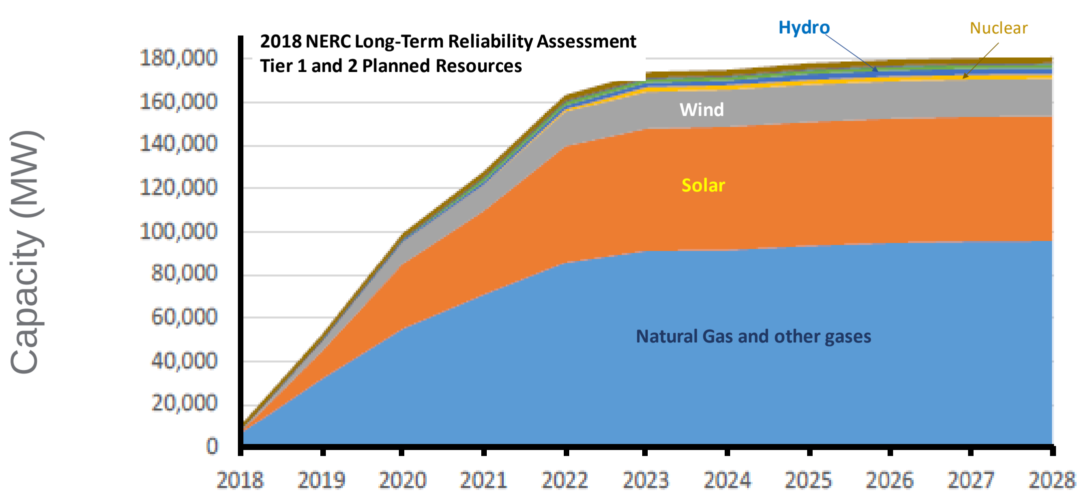


Figure 2~~.~~-22~~.~~ NERC North America Tier 1 and Tier 2 Future Supply Resource Additions

Table 2-3 WI IRP Examples

Utility	Utility Type	Type of Generation Added	When Added	Capacity Added (MW)
Public Service of CO	Investor Owned	Gas Turbines Combined Cycle	2018–2022 2023–2032	1,211 1,929
Public Service of NM	Investor Owned	Gas Turbines Solar PV	2016–2033 2015–2022	736 283
Rocky Mountain Power	Investor Owned	Combined Cycle Wind	2014, 2024 2024	645, 423 432
Arizona Public Service	Investor Owned	Natural Gas (unspecified) Renewable (unspecified)	2019–2029 2019–2029	4,200 425
Tucson Elect. Power	Investor Owned	Natural Gas (unspecified) Renewable (unspecified)	2015–2028 2014–2028	1,214 529
Nevada Power Company	Investor Owned	Combined Cycle Gas Turbines Solar PV	2018–2024 2023–2032 2016–2021	3,813 2,043 50
Sierra Pacific Power Joined NV Energy Sept 2008	Investor Owned	Gas Turbines Combined Cycle	2023–2029 2025	1,975 571
Platte River Power	Municipal Public Utility	Gas Turbines	2021	Unspecified
Colorado Springs Utilities	Municipal Public Utility	Gas Turbines Renewable (unspecified)	2029–2031 2018–2029	39 20
Tri-State G&T Assn.	Cooperative Public Utility	Combined Cycle Renewable (unspecified)	2019–2026 2016–2027	1,176 350
Salt River Project	State Public Utility	Natural Gas (unspecified)	FY2018+	Projected 581 MW gap in 2017

This page left intentionally blank.

3.0 Capacity Expansion Models

The economic value of firm hydropower capacity can be estimated by comparing system capacity expansion costs under a scenario with an existing hydropower plant (actual case) and a scenario without the hydropower plant (counterfactual case). As discussed in Section 2.7, the counterfactual case tends to be more expensive because new supply resources need to come online sooner than under the actual/with-hydropower case. Both with- and without-hydropower economic costs can be estimated by capacity expansion models.

As shown in Figure 3-1, capacity expansion tools determine the "optimal" expansion (i.e., what supply resource candidates to bring online and when to bring them online). That is, it determines the time pathway of feasible combinations of new candidate technology construction that minimize costs. Expansion candidates include, but are not limited to, generation technologies (e.g., gas turbines, natural gas combined cycle, hydropower) and DSM initiatives. Some, but not all, tools also determine the area (e.g., BAA) or location where new technologies should ideally be constructed. Starting from the initial supply and demand state of the current system, most capacity expansion tools simulate system operation and production costs under various future system states. Each state consists of a unique combination of system requirements (e.g., loads, reliability target), existing resources adjusted for future resource changes, and new candidate additions. The timeline of future changes, such as announced unit retirements and online dates of new additions, that are either under construction or planned are sometimes fixed (represented as given values) within the modeling framework. By eliminating the states that do not meet various criteria such as RM targets, loss-of-load probability (LOLP) criteria, renewable portfolio standards, emissions limits, and so forth, the model ensures that the "best" path forward meets the entity's expansion goals and complies with regulatory and statutory requirements.

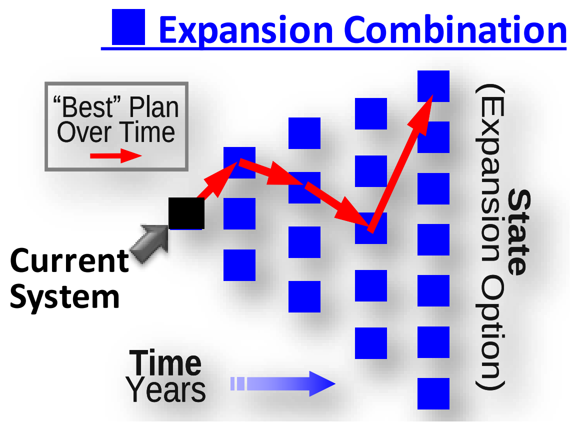


Figure 3-1 Capacity Expansion Pathway

Because expansion models have a finite time horizon, newly built supply resources typically have an operational lifetime and value that go beyond the last modeled year. The remaining value of a resource is referred to as a "salvage" value, which is a measure of the plant's capital worth at the end of the modeled time horizon. Some models account for these economic end-effects by estimating the salvage value of each newly model-built resource at the end of the last simulated year. Salvage values are then discounted via a NPV calculation. Another methodology that yields a very similar result is to treat capital expenses as levelized capital payments during the simulated years when new plants operate.

For each system capacity expansion state (i.e., each square in Figure 3-1), the model simulates the system dispatch and calculates the associated productions costs. This calculation also includes estimated societal costs associated with energy that is not served for system resources. Given system production costs, capital investment costs, and fixed O&M costs for each state, capacity expansion tools determine the best temporal pathways, including new supply resource online dates and DSM initiatives additions over time. Typically, the "best" plan is one that has the lowest NPV of expenditures over time from either an economic viewpoint or from the financial perspective of an entity that constructs additional supply resources.

There are several modeling tools and packages that vary in the level of detail and complexity at which they simulate power system capacity expansion and DSM pathways over time. A tool that has been utilized internationally for decades is the Wien Automatic System Planning Package.[29] Distributed by the International Atomic Energy Agency, it utilizes a dynamic programming technique to find the least-cost expansion path. A few other expansion tools include AURORA[30] and Plexos,[31] which are both marketed by Energy Exemplar; the National Energy Modeling System[32] developed by Energy Information Administration (EIA); and the Regional Energy Deployment System,[33] developed by the National Renewable Energy Laboratory (NREL).

Between January and October 2017, environmental operating criteria at GCD specified under the 2016 LTEMP ROD Preferred Alternative was phased in. This reduced both GCD flexibility and firm capacity. As part of the analysis that was conducted in support of the LTEMP EIS, Argonne National Laboratory (Argonne) estimated reductions in the firm capacity credit under various LTEMP EIS alternative operating criteria. Figure 3-2 shows firm capacity reductions if LTEMP EIS operating criteria are replaced with those mandated by the 1996 ROD. Note that the left panel shows that the reduction in firm capacity is a function of both the operating criteria and the assumed risk tolerance level (i.e., exceedance level). It also shows that the greatest difference in capacity occurs at the 50% exceedance level and the smallest at the 10% exceedance level.

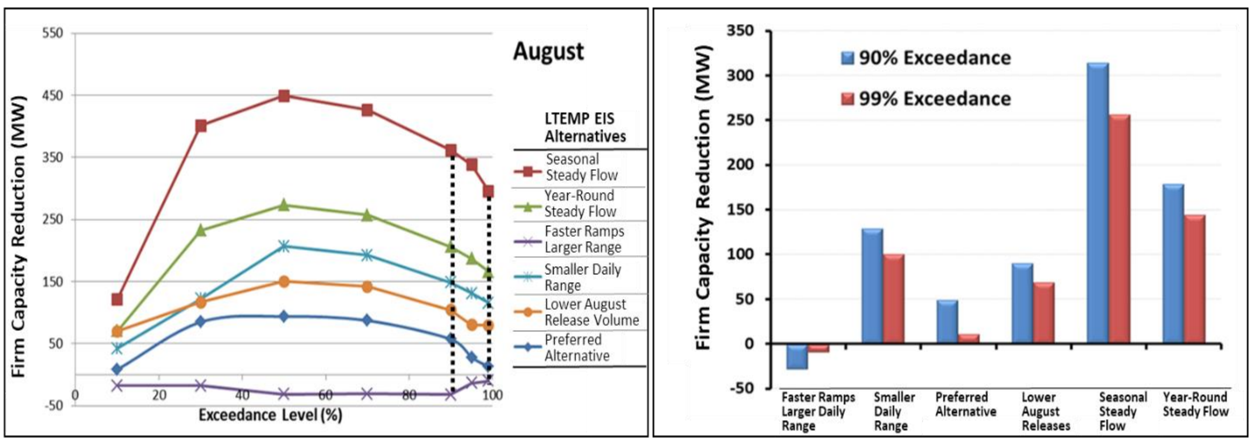


Figure 3-2 Firm Capacity Reductions at GCD under the LTEMP EIS Alternatives

Currently, there are eight generating units at the GCD power plant, with a combined nameplate capacity of 1,320 MW.[34] The largest firm capacity loss shown on the seasonally steady flow curve of 450 MW represents an additional firm capacity loss above the firm capacity loss already caused by the 1996 ROD. This represents an additional 34% loss relative to the nameplate capacity. The seasonally adjusted steady flow alternative had the greatest capacity loss because, under this alternative, hourly water releases during

[29] International Atomic Energy Agency, *2001, Wien Automatic System Planning (WASP) Package: A Computer Code for Power Generating System Expansion Planning, Version WASP-IV, User's Manual*, Vienna. https://www-pub.iaea.org/MTCD/Publications/PDF/CMS-16.pdf.

[30] Energy Exemplar PLEXOS, 2020, "AURORA Electric Modeling Forecasting and Analysis Software." https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/.

[31] Energy Exemplar PLEXOS, 2020, "PLEXOS Market Simulation Software." https://energyexemplar.com/solutions/plexos/.

[32] EIA, 2019, "Availability of the National Energy Modeling System (NEMS) Archive," January 24. https://www.eia.gov/outlooks/aeo/info_nems_archive.php.

[33] NREL, undated, "Regional Energy Deployment System Model." https://www.nrel.gov/analysis/reeds/.

[34] U.S. Bureau of Reclamation, undated, "Glen Canyon Powerplant." https://www.usbr.gov/projects/index.php?id=522

each season must be constant (i.e., there is no operational flexibility). It also required monthly water releases to closely follow a more natural hydrograph, which tends to have relatively low water releases during the summer peak-load months. The alternative that allows for a larger daily range and faster hourly water release ramp rates was estimated to slightly increase GCD hydropower plant firm capacity.

Because historically the CRSP Management Center risk tolerance for firm electric service (FES) marketable capacity was approximately 10%, the determination of firm capacity for all LTEMP alternatives was also based on this risk level. Furthermore, it was assumed that in the future annual peak load would occur in August. Depending on the alternative, lost capacity under the 10% risk level is between approximately -25 and 310 MW. Because historically the peak grid load occurred in July as well, a sensitivity firm capacity was computed for that month. However, results were only slightly different. Sensitivity analyses of firm capacity losses were also estimated at more conservative risk levels. Both absolute firm capacities and differences among alternatives at lower risk tolerance levels were smaller.

This page left intentionally blank.

4.0 Hydropower Energy

4.1 Overview of Hydropower Energy Contributions to the U.S. Electricity Sector

In terms of energy generated, hydropower represents 7% of the total electricity produced in the United States between 2007 and 2016 (Figure 4-1). During this period, it was the renewable energy source with the highest energy contribution in the United States, well ahead of other sources such as wind (3%) and solar (less than 1%).[35] This contribution to the energy mix was not constant over the years. Between 2007 and 2016, the annual generation contribution from hydropower ranged from 6.6% to 8.4% (Figure 4-2). The largest hydropower contribution happened in 2011. An exceptional amount of water was available this year, due to an unusual combination of warm, wet weather that melted low-elevation snow in the northwestern United States.[36] In contrast, the west coast experienced severe, increasing droughts from 2013 to 2015, which led to significant declines in hydroelectric generation.[37]

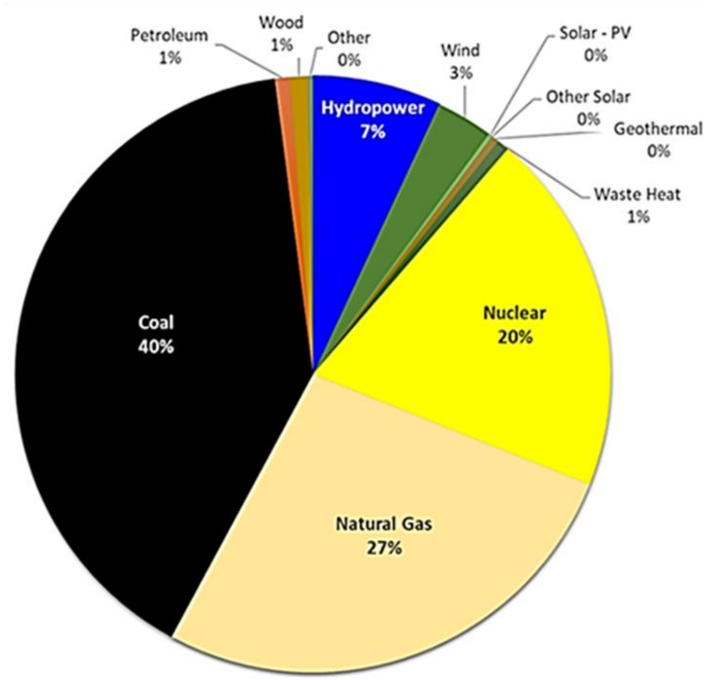


Figure 4-1 U.S. Energy Generation Contribution by Technology, 2007–2016

Figure 4-3 shows that monthly U.S. total generation, hydropower generation, and reliance display a distinct annual cycle from 2007 to 2016 with a peak reliance of over 11% in the spring of 2011, the year with the highest recent annual generation. Hydropower generation is essentially dependent on water availability, and the monthly hydropower generation pattern is not correlated with the electricity generation/demand pattern. Demand is generally low during spring, when water availability is the highest. This is why the hydropower contribution to the energy mix is also the highest during this season.

[35] EIA, 2017, "Form EIA-860." https://www.eia.gov/electricity/data/eia860/

[36] EIA, 2012, "Northwest hydroelectric output above five-year range for much of 2011," February. https://www.eia.gov/todayinenergy/detail.php?id=5070#.

[37] EIA, 2015, "Hydropower conditions improve as West Coast drought eases," May. https://www.eia.gov/todayinenergy/detail.php?id=26332.

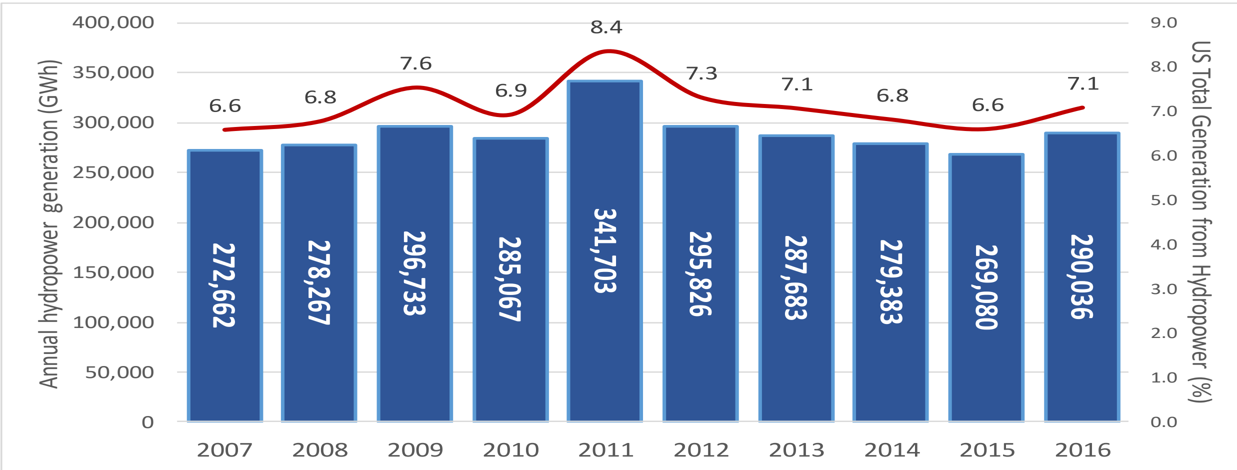


Figure 4-2 Annual U.S. Hydropower Generation Level and Reliance, 2007–2016

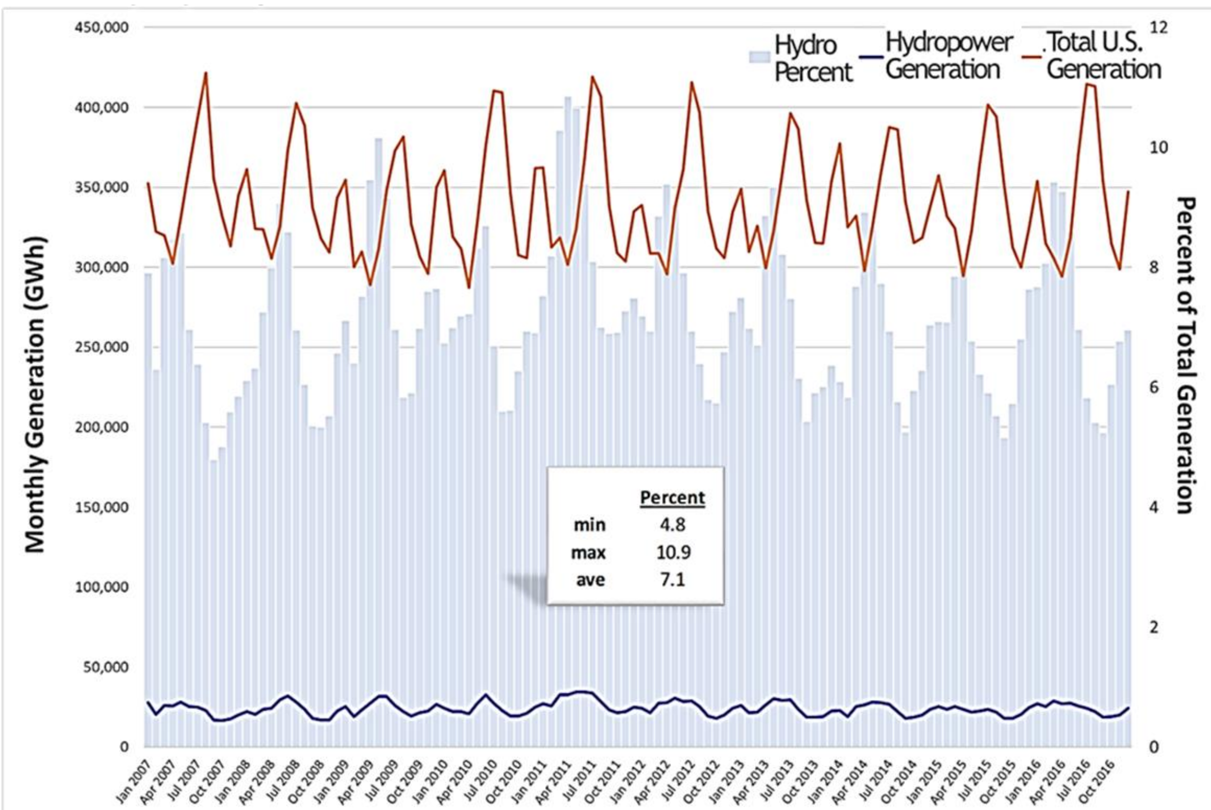


Figure 4-3 Monthly U.S. Total Generation, Hydropower Generation, and Reliance, 2007–2016

Overall, the monthly reliance on hydropower follows an annual cycle, with a national peak reliance of 9% during the spring (April and May) when snow is melting, and low national reliance of 5.5% reached at the end of the summer (September) when weather is dry (Figure 4-4). The reliance often reaches a local minimum around February as well, when less water flows because a significant amount of precipitation falls as snow. Indeed, snow sometimes may be stored in a solid state for months until it melts in the spring and summer.

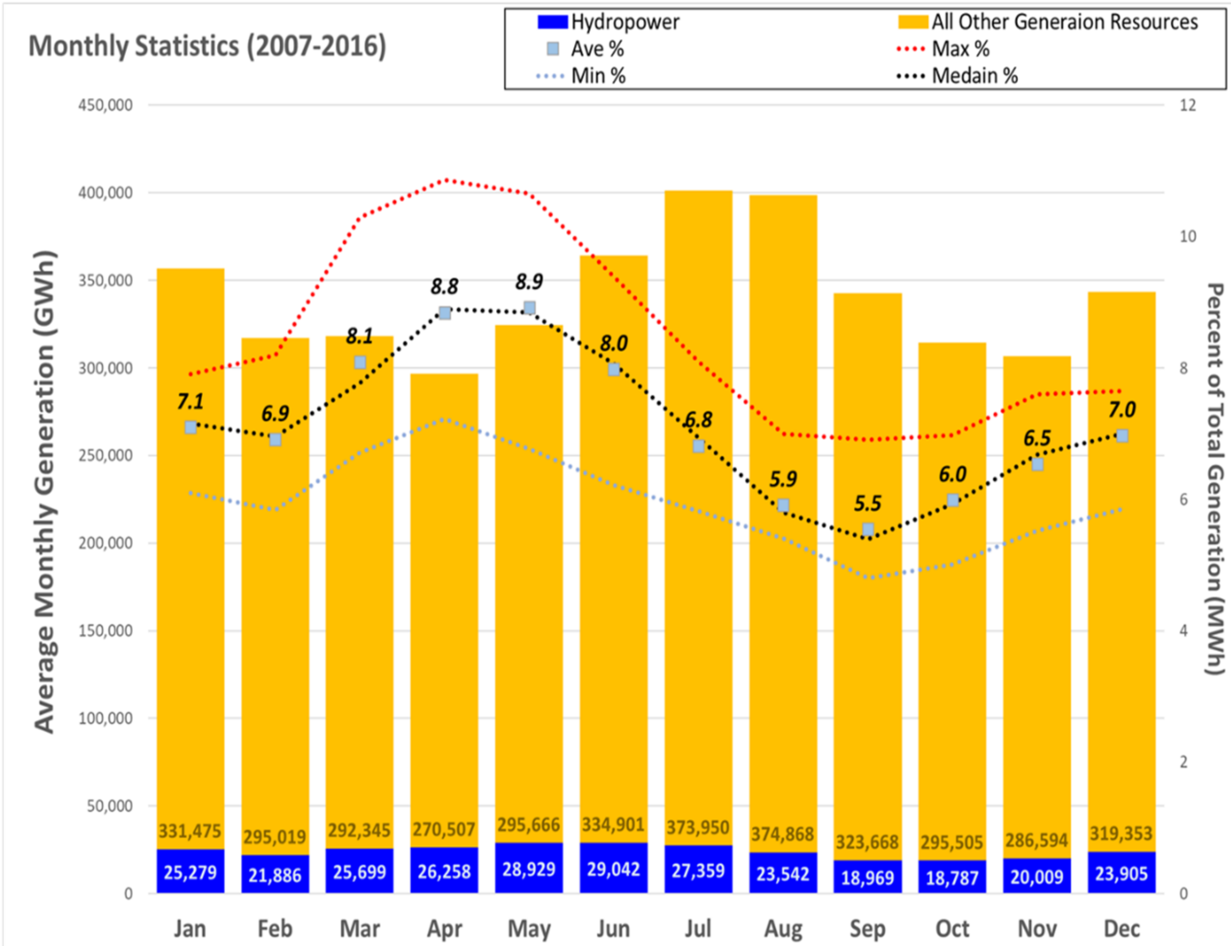


Figure 4-4 Average Monthly Generation of Hydropower and Other Sources, 2007–2016

The hydropower contribution to the U.S. energy mix also varies significantly among regions. Such differences in the contribution are observed among NERC regional entities (REs). Until July 2018, NERC oversaw 10 regional reliability entities: Alaska Systems Coordinating Council (ASCC), Florida Reliability Coordinating Council (FRCC), Hawaii Island Coordinating Council (HICC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), Texas Regional Entity (TRE), and WECC.[38] An approximate representation of the RE footprints between 2007 and 2016 is depicted in Figure 4-5.

The geographic distribution of these REs recently changed when of one of them was dissolved. The dissolution of the RE SPP was approved by FERC in May 2018 and has been effective since July 1, 2018. Following this decision, the SPP footprint transferred to the RE MRO.[39]

[38] VERSIFY, 2020, https://www.versify.com/the-nerc-reliability-regions/.

[39] 163 FERC ¶ 61,094, 2018, United States of America Federal Energy Regulatory Commission, "Order Granting Approvals in Connection with the Dissolution of the Southwest Power Pool Regional Entity", May, https://www.ferc.gov/CalendarFiles/20180504141902-RR18-3-000.pdf

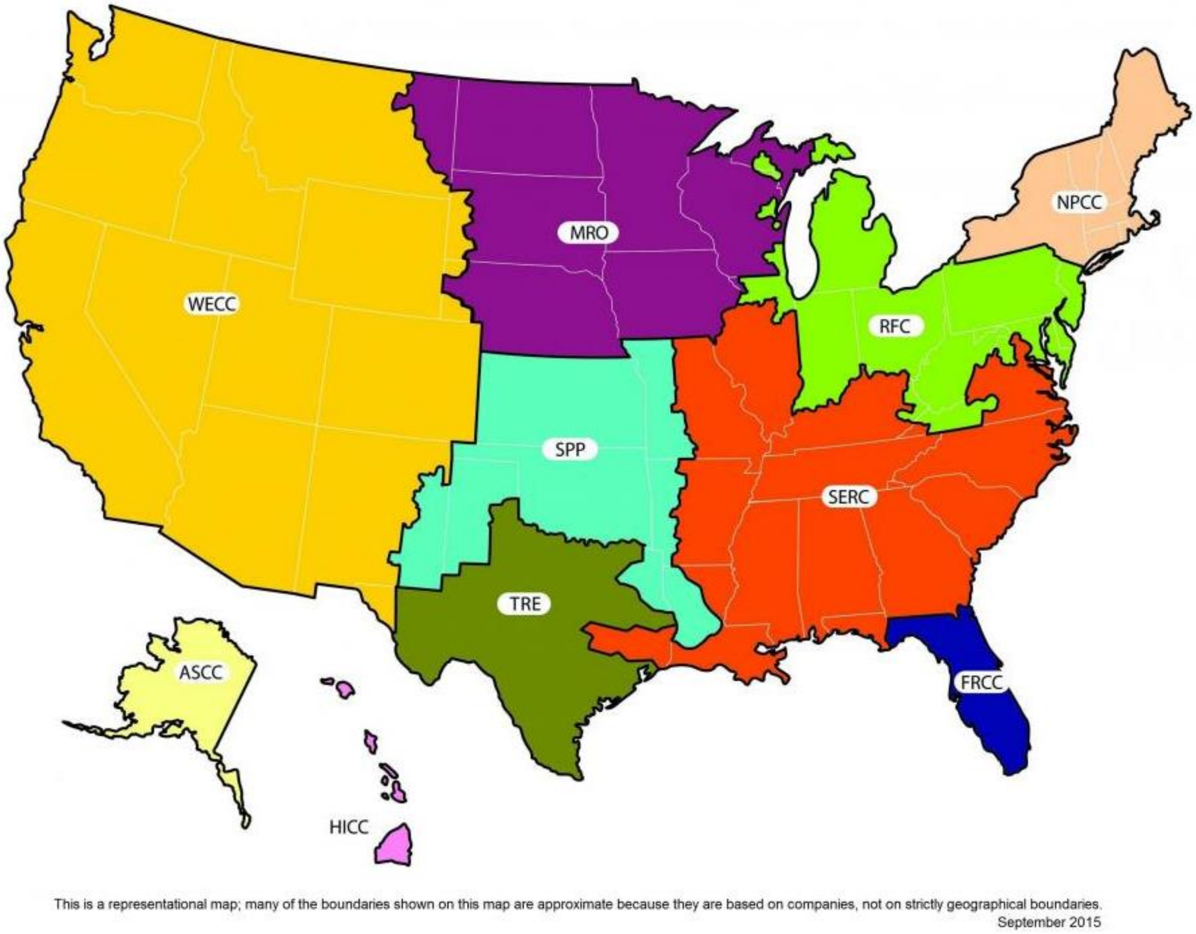


Figure 4-5 Approximate Representation of the NERC REs, September 2015

WECC accounts for most of the hydropower generation in the United States; it was responsible for 60.5% of the energy produced from 2007 to 2016 (Figure 4-6). SERC and NPCC are respectively the second and third highest hydropower energy producers, producing 15.9% and 12.4%, respectively, of the total hydropower energy in the United States.

Figure 4-7 shows that during the same 2007 to 2016 period, the top three NERC REs with the highest reliance on hydropower, in terms of hydropower contribution to total regional power generation, were WECC (23.9%), ASCC (22.1%), and NPCC (14.2%). Note that ASCC is a NERC region with a very low energy demand, compared to that of WECC or NPCC. However, the percentage of the demand served by hydropower energy in ASCC is similar to that of WECC.

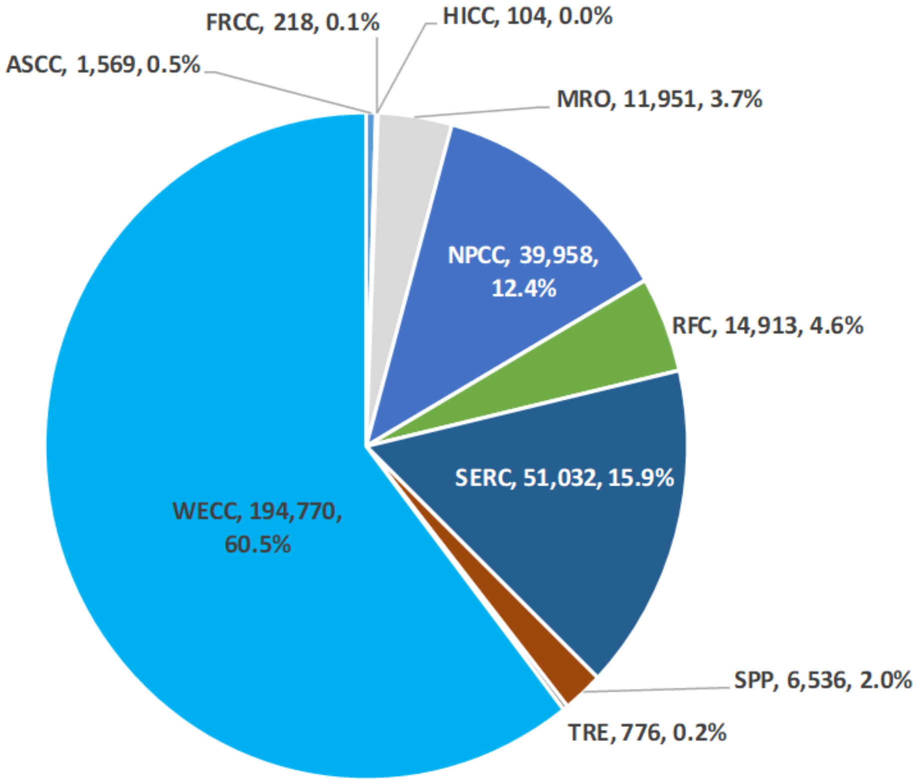


Figure 4-6 Hydropower Generation Distribution by NERC RE, 2007–2016

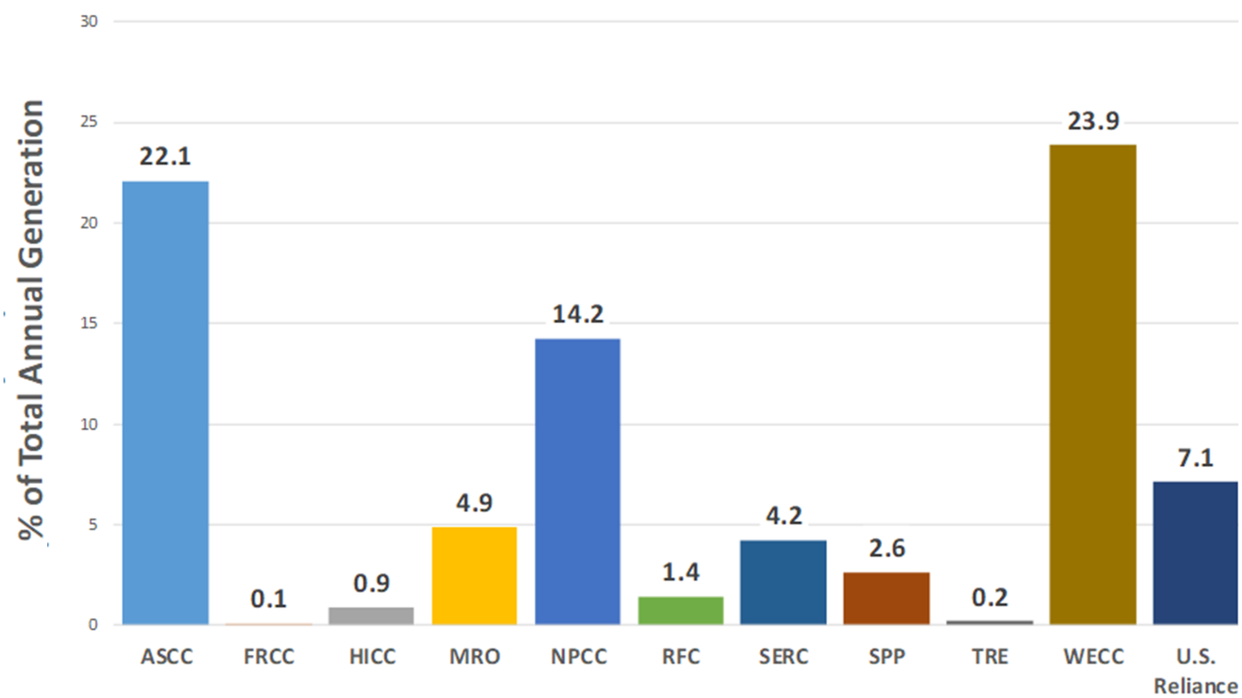


Figure 4-7 Reliance on Hydropower Generation for Each NERC RE, 2007–2016

Because WECC accounts for more than half of the U.S. hydropower production, the monthly U.S. hydropower reliance pattern is mainly driven by the WECC contribution (Figure 4-8 and Figure 4-9). Monthly hydropower reliance in other regions, such as ASCC and HICC, experiences different monthly patterns of hydropower generation and reliance. The WECC pattern is distinctly different from the pattern of other REs, because most of the precipitation in the WECC falls in mountainous parts of the region during the winter and is stored as snow and ice until it melts later in the year. As high-altitude weather warms during the late spring and early summer, inflows in river basins dramatically increase.

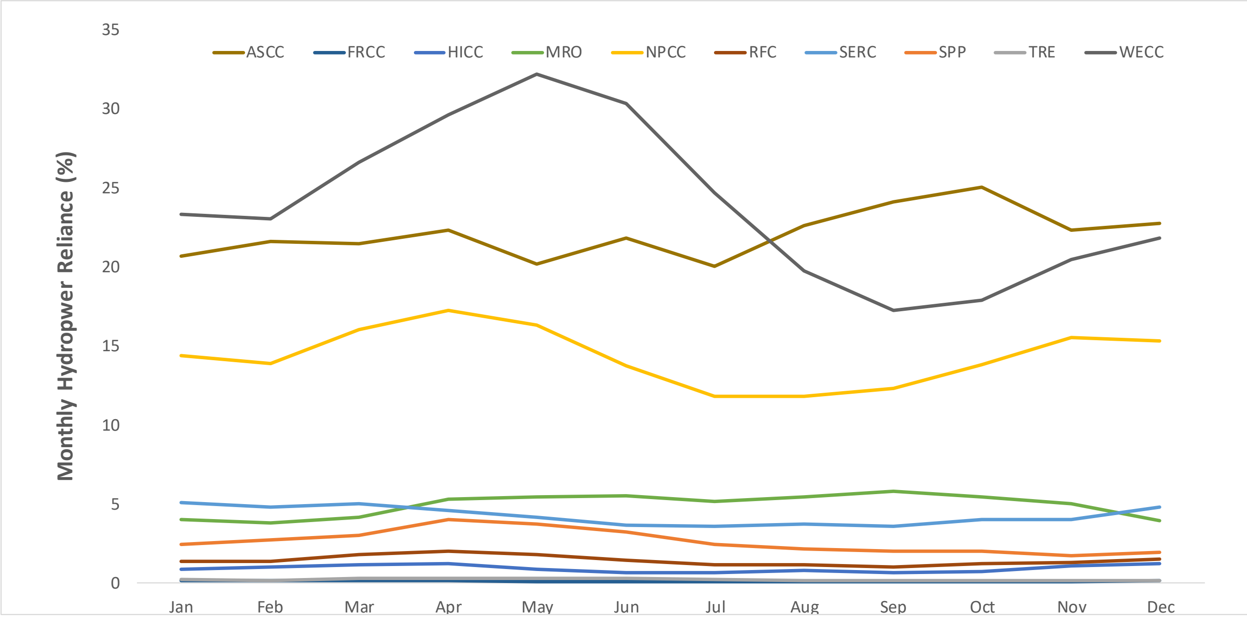


Figure 4-8 Average Monthly Reliance on Hydropower Energy Production for Each RE, 2007–2016

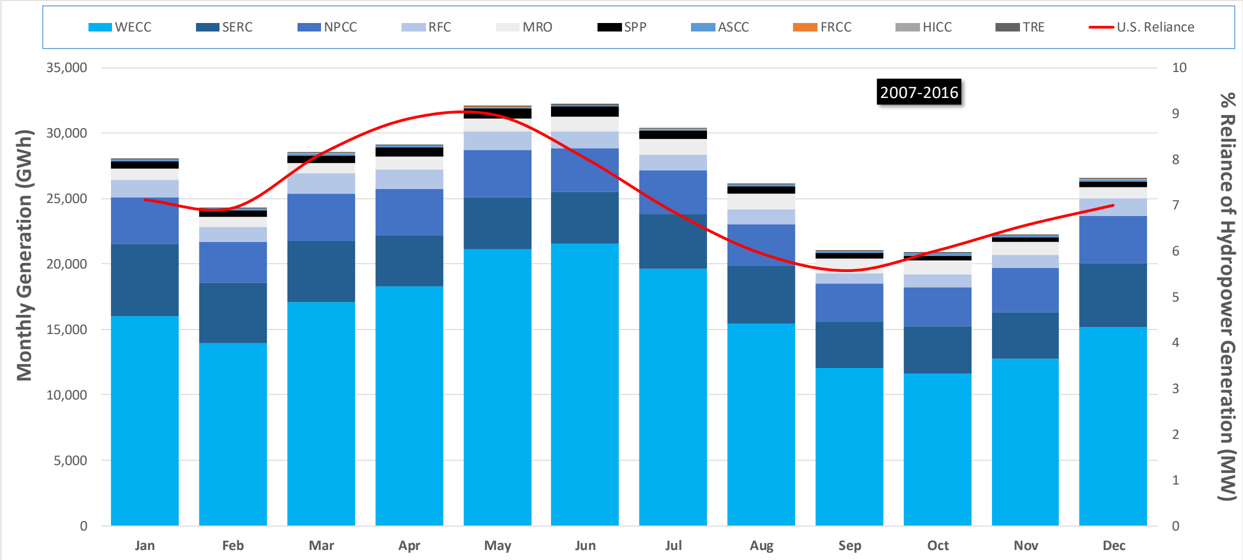


Figure 4-9 Average Monthly Generation of Hydropower, and Distribution by RE, 2007–2016

Because WECC has a large influence on hydropower generation patterns in the United States, this report will drill further down into the details of the WI. The WECC RE is divided into the 38 BAs in Figure 2-2. Hydropower generation in the WECC is the highest in the Pacific Northwest, where BPA and Chelan County account for more than half of WECC hydropower production. As shown in Figure 4-10, between 2007 and 2016, on average, BPA alone accounted for 46% of WECC hydropower energy production.

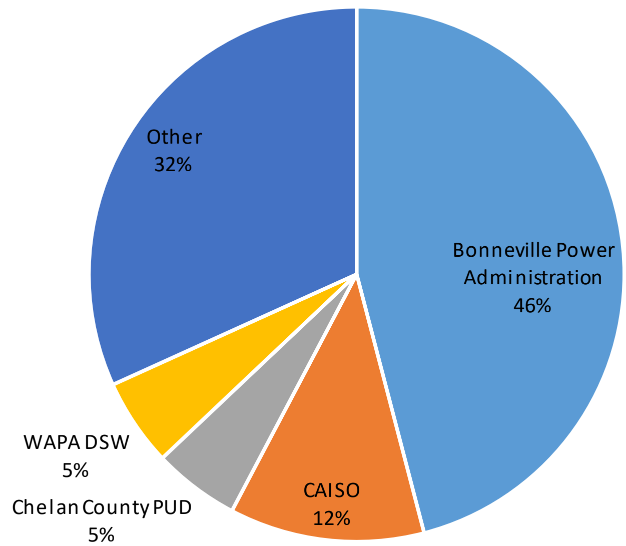


Figure 4-10 Distribution of WECC Hydropower Generation by BA, 2007–2016

Reliance on hydropower energy, in terms of hydropower generation relative to total production, is only 7% at the national level. However, this proportion is significantly higher in some BAs of the WECC. As shown in Figure 4-11, in 10 of the 38 BAs, including BPA and the WAPA Desert Southwest (DSW) region, the amount of hydropower energy produced actually exceeds the demand level. However, in BAs with relatively high demand, such as CAISO, the amount of hydropower energy produced is still lower than the demand level, with an average reliance of 23.9% between 2007 and 2016.

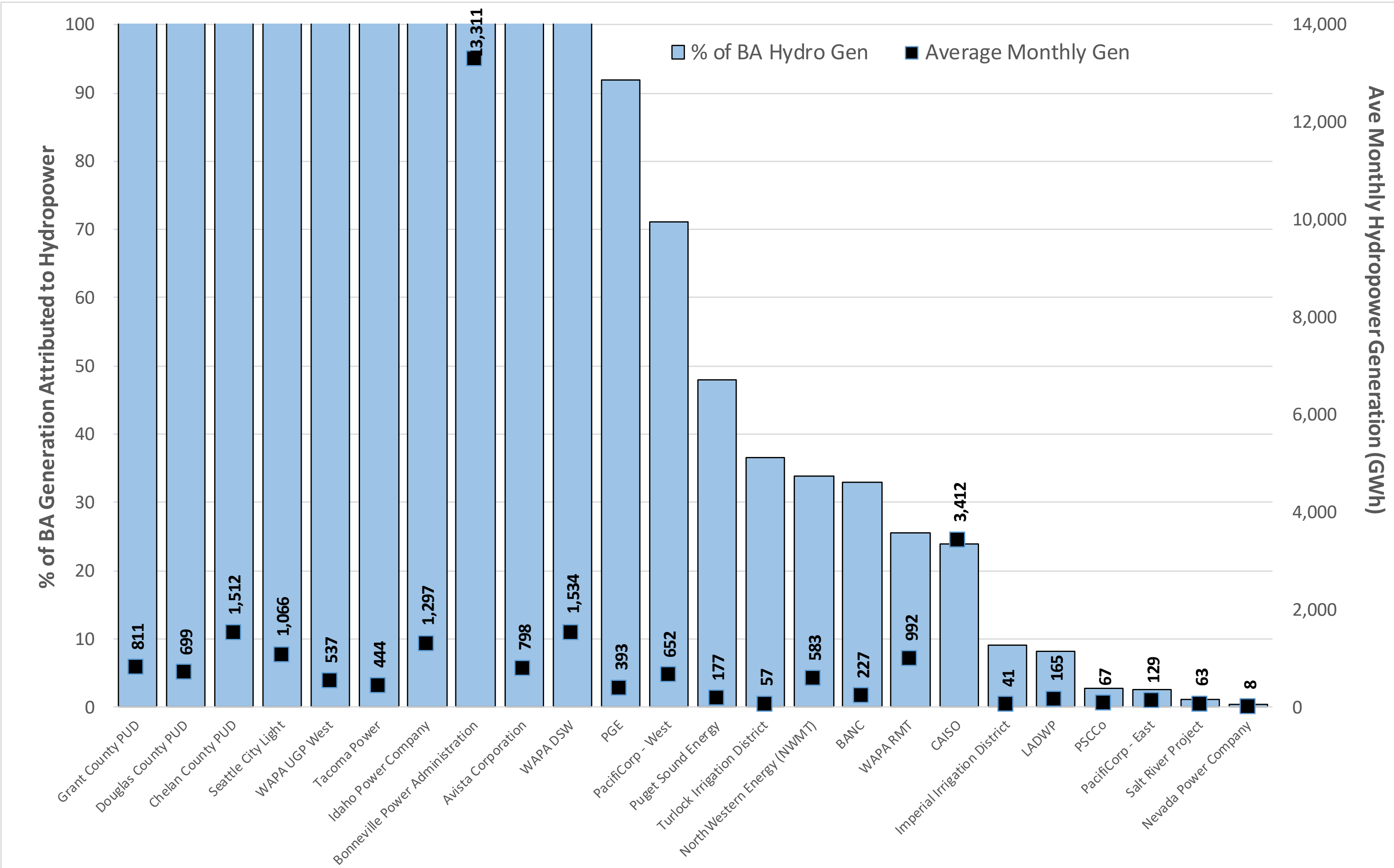


Figure 4-11 Hydropower Reliance for BAs in the WI, 2007–2016

4.2 Hydropower Energy Trends and Diversity

Individually, hydropower plants are subject to large, naturally occurring, hydrological fluctuations. For example, monthly hydropower generation at even hydropower plants with large water storage reservoirs are subject to large fluctuation in monthly generation levels. As discussed in Section 6, this volatility tends to increase as water storage decreases. Because of this uncertainty, hydropower resource planning, scheduling, and dispatch must be performed conservatively in order to accommodate fluctuations that are often difficult to predict; that is, there is a relatively high degree of forecast error. However, relative volatility tends to decrease as the hydropower footprint expands. The reduction in volatility as a function of footprint size has also been demonstrated with other renewable energy resources such as wind and solar. VAR diversity has a host of advantages, such as lower BA flexibility requirements.

In general, hydropower production diversity (a low correlation among resources) is beneficial because temporal volatility is reduced. That is, lower fluctuations over time result in an aggregate hydropower energy resource that is more dependable, has a higher level of certainty, and poses lower supply risks to the system operators. This higher level of certainty is not only beneficial from an energy production standpoint, but as discussed in Section 2.7, leads to a higher level of firm capacity (see Figure 2-17) than the individual power plant firm capacity values (i.e., diverse aggregate resources have more value than the sum of its individual standalone components).

As discussed in this section, there is a significant diversity across hydropower resources both at the regional levels and between individual hydropower plants at disparate locations. At the national level, the water availability profile among hydropower plants, which is driven by hydrological processes, is geographically diverse. Because of this, the generation profiles of hydropower plants, especially those that are located far away from each other, are poorly correlated.

This absence of correlation is evident when comparing the monthly hydropower generation profile of the WECC to the rest of the United States. Figure 4-12 shows that, between 2007 and 2016, monthly generation of WECC tended to decrease over time, whereas it tended to slightly increase in the rest of the United States. Also note that there were periods of time when generation patterns exhibited similar trends, and other periods of time when the two graphs diverged.

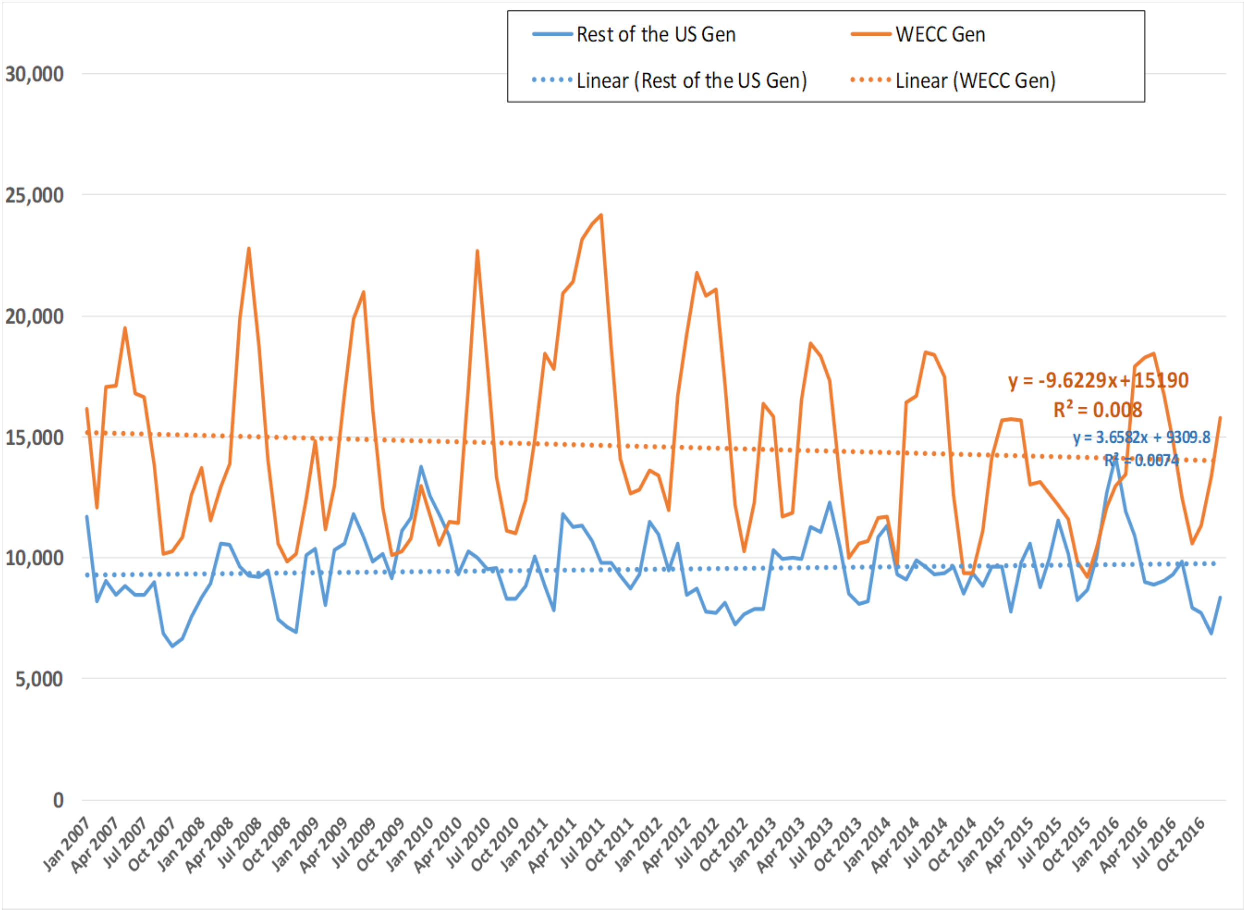


Figure 4-12 Monthly Generation (GWh) of the WECC vs. the Rest of the United States (outside of WECC)

Figure 4-13 depicts the correlation between the generation profiles of the WECC and those of the rest of the United States. The very low coefficient of determination, R^2, between the two profiles is one measure indicating that the two patterns are very poorly correlated. However, the positive slope of the linear regression shows a slight tendency for both generation profiles to be at lower or higher levels at the same time.

Figure 4-14 illustrates the correlation between the change in hydropower generation from one month to the next in WECC and the corresponding monthly hydropower generation change in the rest of the United States. The very low coefficient of determination confirms the poor correlation between the two patterns. However, the negative slope shows a slight tendency for the two profiles to change in opposite directions; that is, as WECC hydropower generation increases, there is a slight overall tendency for generation in the rest of the United States to decrease, and vice versa.

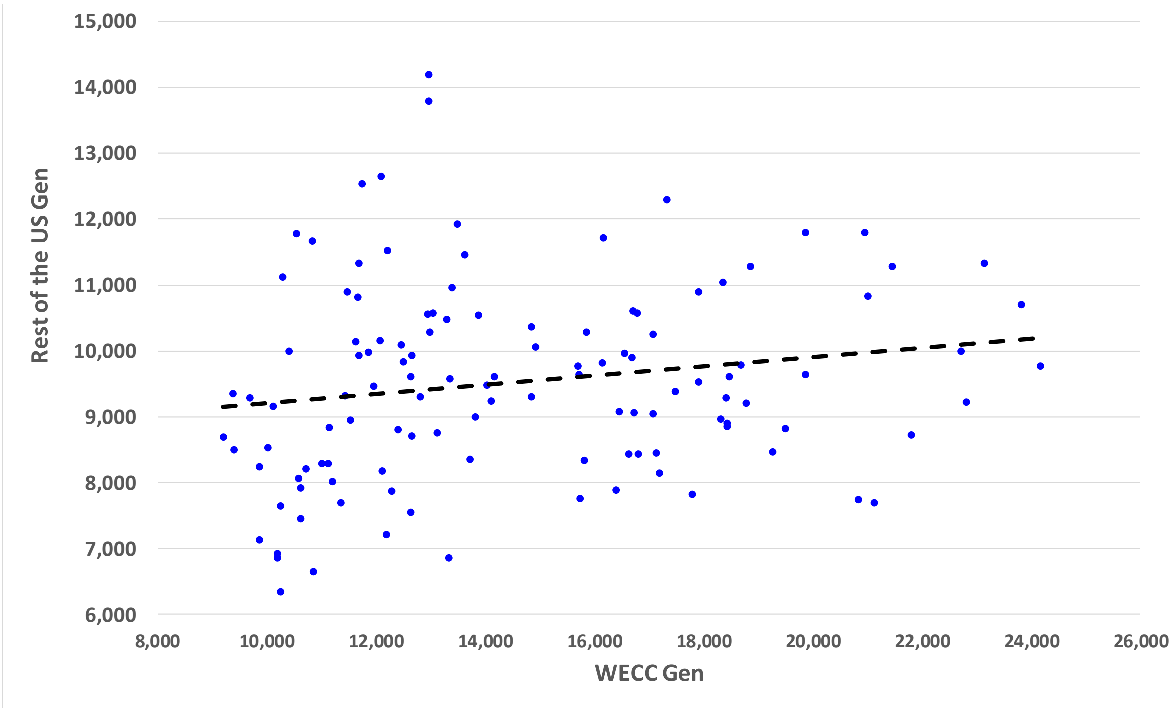


Figure 4-13 Monthly Generation (GWh) in the WECC vs. Generation in the Rest of the United States

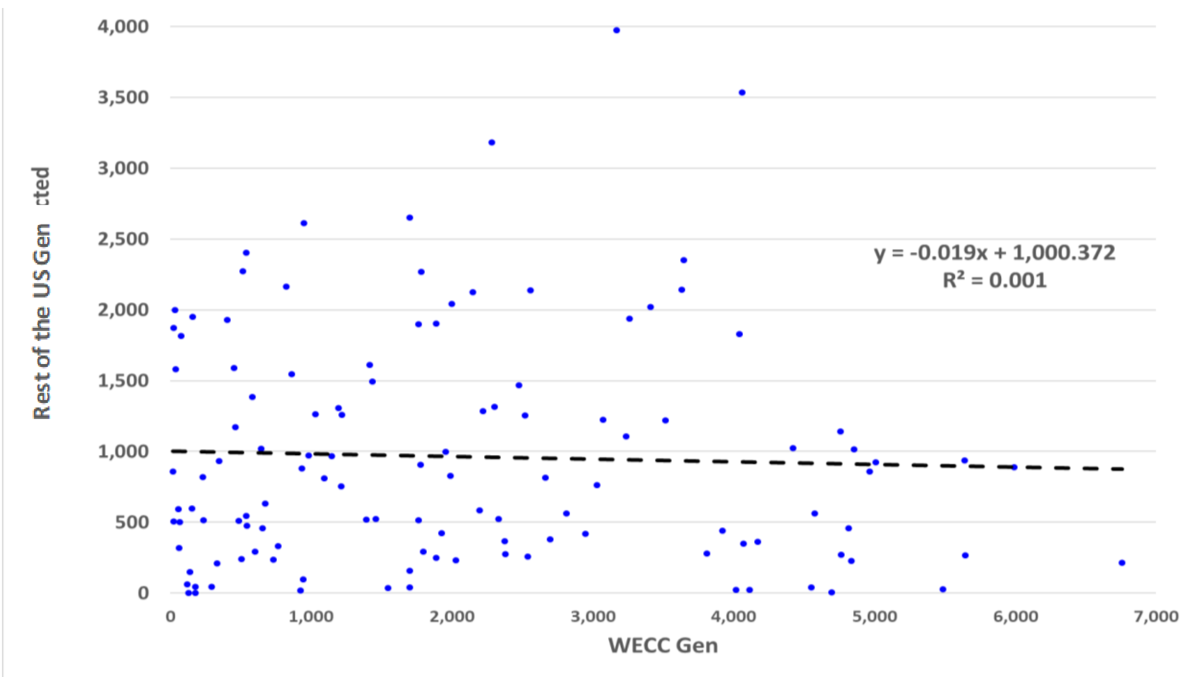


Figure 4-14 Generation Change between Consecutive Months (GWh) in the WECC vs. Generation Change in the Rest of the United States

Because hydropower generation is regionally diverse, the aggregated national hydropower generation profile exhibits a more homogenous range of generation levels. Figure 4-15 represents the exceedance probability curves of the two areas. The left panel shows monthly hydropower generation exceedance curves, and the normalized curves are shown in the right panel. The exceedance probability curve was described in Section 2.6.

As a reminder, the exceedance probability curve represents the monthly generation profile sorted in decreasing level order. It allows one to directly measure what percentage of the time the generation level is at or above a specific value. The larger the range and the steeper the curve, the higher the generation volatility. For example, if monthly generation levels never changed, the exceedance curve would be flat.

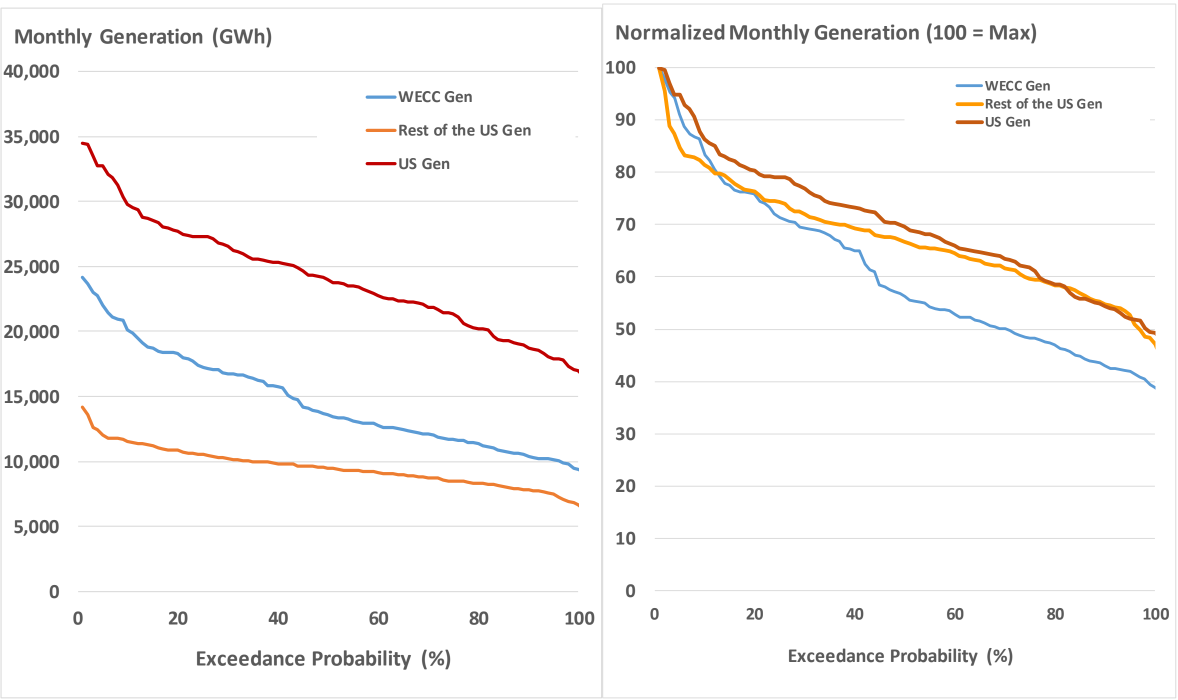


Figure 4-15 Exceedance Curve of Hydropower Generation in the WECC, in the Rest of the United States, and at the National Level: Absolute Value (left), and Percentage of Maximum Generation Level (right)

The normalized curve displays exceedance values relative to the higher observation. For example, if a specific month has a generation level that is half of the highest observation, it is assigned a normalized value of 50%. These curves show that WECC generation has significantly more variability than both the area outside the WECC and the United States as a whole. Note that as the footprint increases, the diversity also increases.

Figure 4-16 shows that the WECC distribution is bimodal and positively skewed (with a peak at low values), whereas the rest of the United States exhibits a normal distribution more negatively skewed (with a peak at higher values). The combination of the two areas generates a profile with a more homogenous distribution, and thus a more diverse range of generation. The positive skew from the WECC distribution greatly limits the firm capacity. When combining the two areas, notice that the normalized exceedance curve (the red line in Figure 4-15) is usually above the two other curves, which means that the average monthly generation at the national level is closer to its maximum level, and thus flatter, than for each area taken independently.

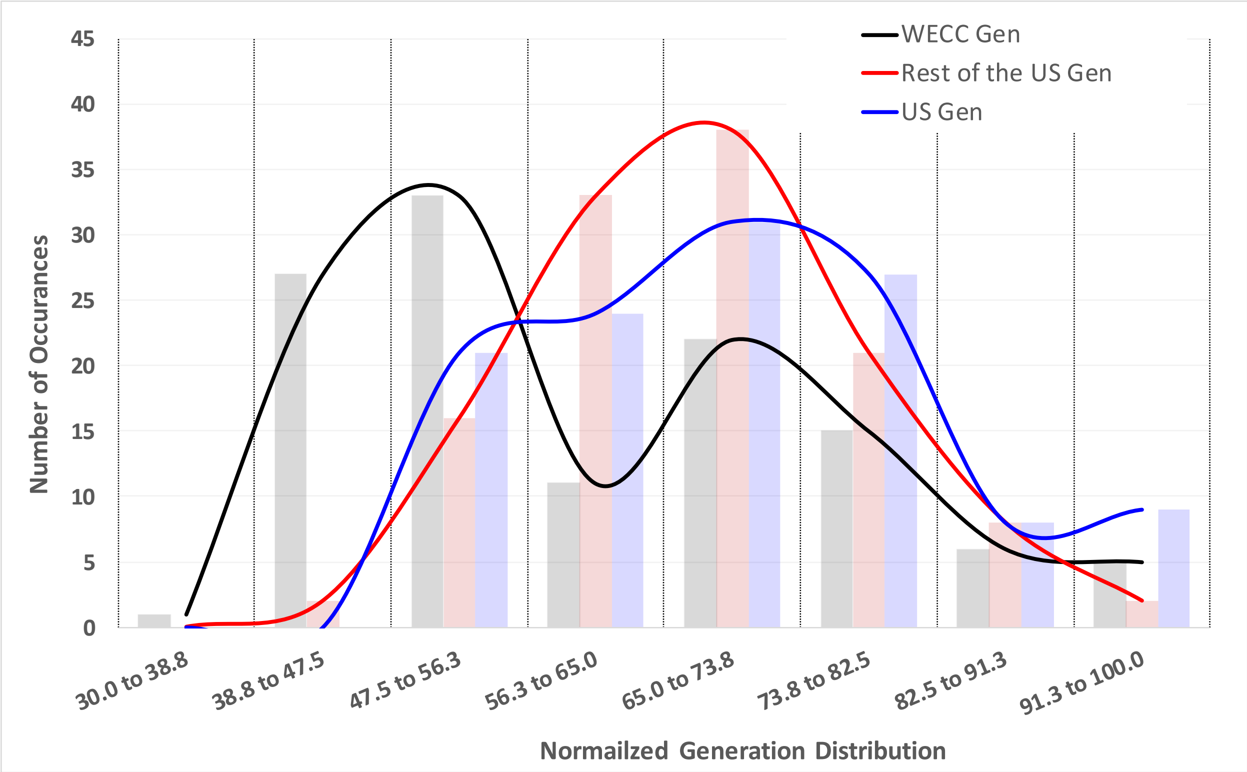


Figure 4-16 Statistical Distribution of Normalized Hydropower Generation in the WECC, in the Rest of the United States, and at the National Level

At a more granular (i.e., smaller) geographical scale, hydropower diversity tends to be lower (i.e., it tends to be more homogeneous). Figure 4-17 illustrates the monthly generation profile in BPA, which is part of the WI, and in the rest of the WI. It is clear that the two profiles exhibit similar patterns. This is verified by Figure 4-18, which compares the monthly generation level at BPA to the monthly generation level in the rest of the WI. The coefficient of determination between the two profiles is clearly much higher than when we were comparing the two larger areas (e.g., WECC compared to the United States outside of WECC). This correlation, however, is somewhat weaker when comparing monthly changes in generation level between BPA and the rest of the WI (Figure 4-19). This means that, on a monthly basis, generation in BPA will not necessarily decrease or increase at the same time as in the rest of the WI.

The correlation between BPA and the rest of the WI is not representative of the large spectrum of correlations there are between all BAs within the WI. Figure 4-20 shows four different cases and compares two distinct areas within the WI. Among the four cases, the coefficient of determination between the two monthly generation profiles ranges from 0.002 to 0.690.

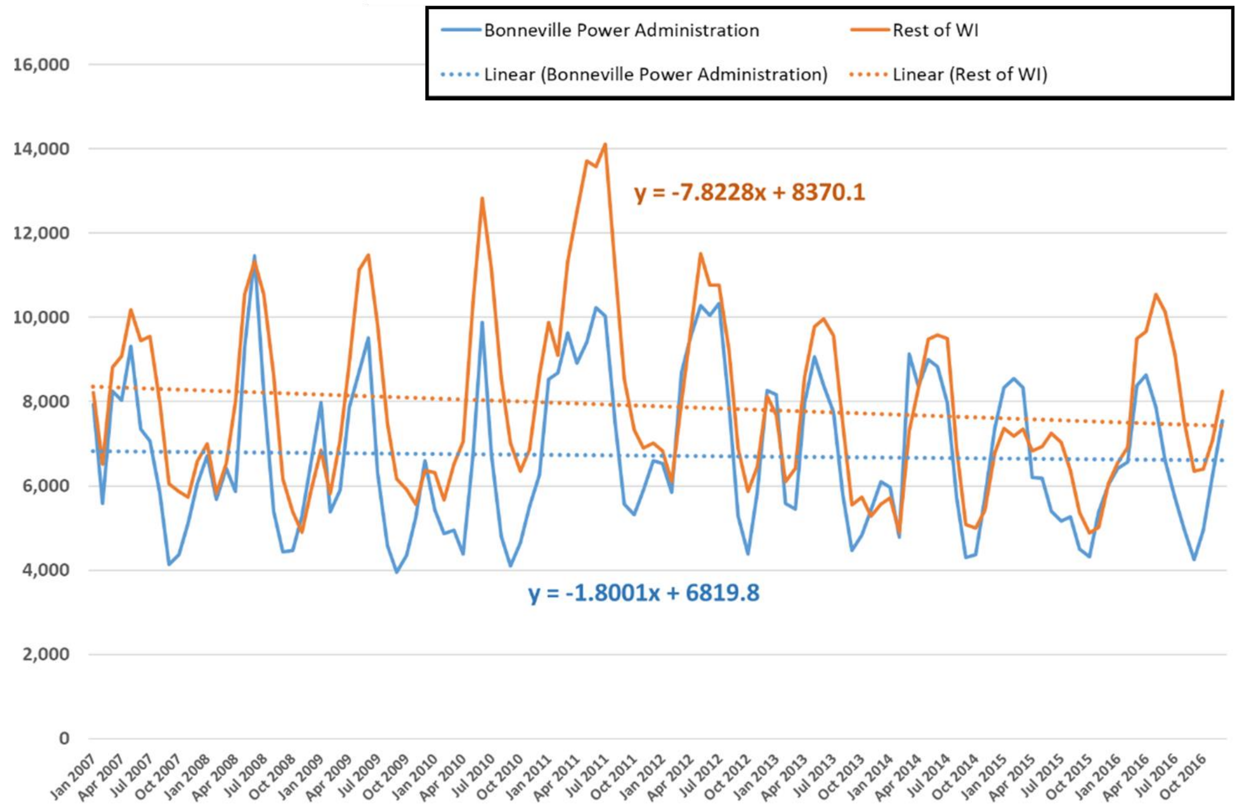


Figure 4-17 Monthly Generation (GWh) Profile of BPA vs. the Rest of the WI

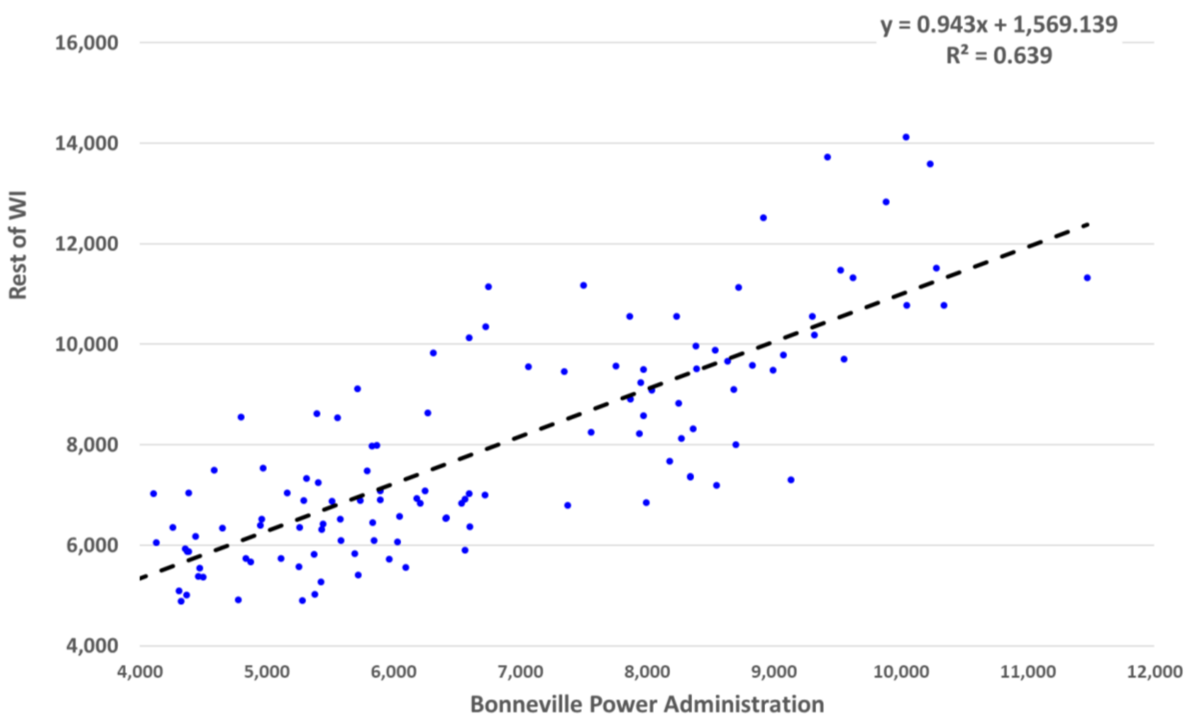


Figure 4-18 Monthly Generation (GWh) in BPA vs. Generation Level in the Rest of the WI

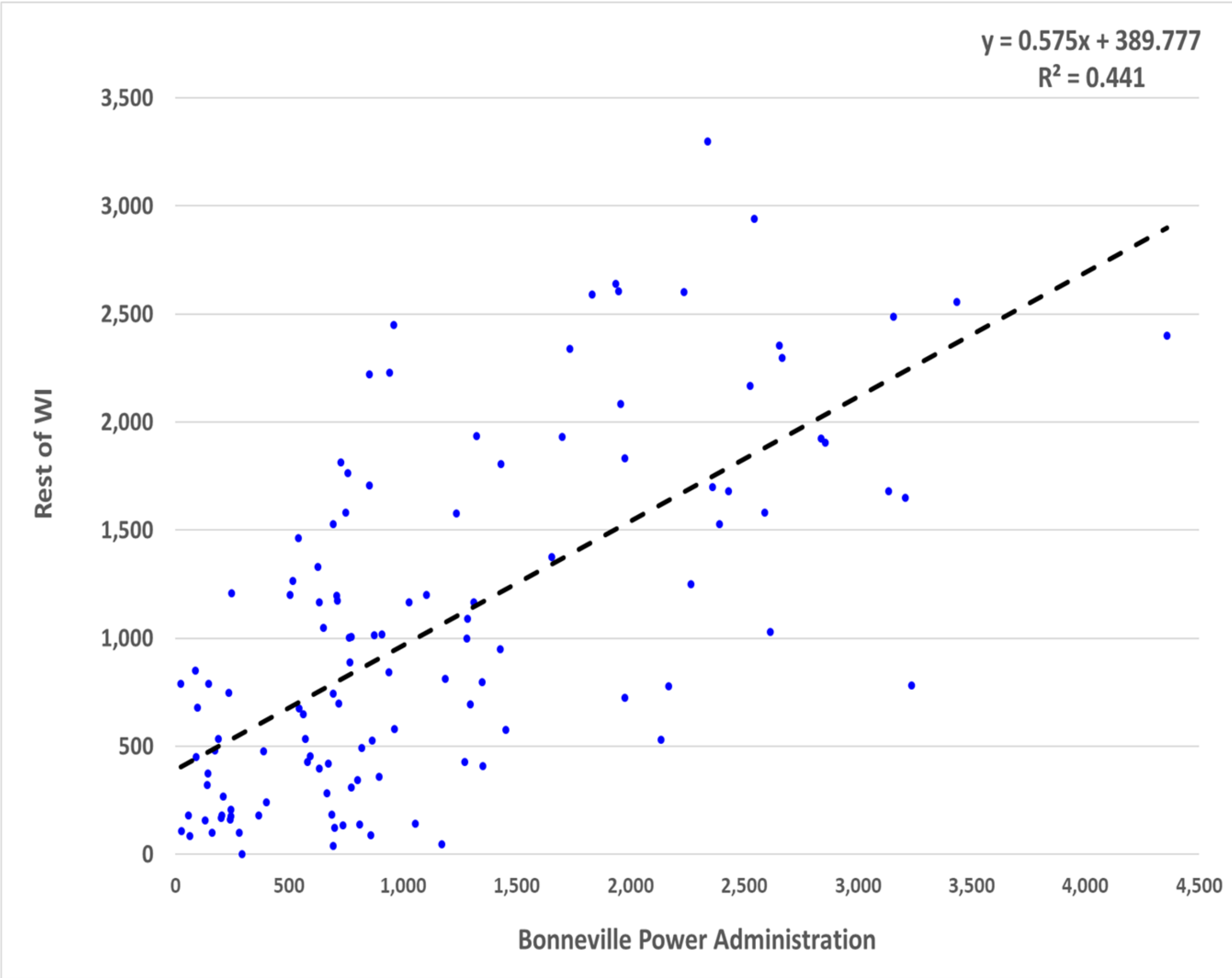


Figure 4-19 Monthly Generation Change between Consecutive Months (GWh) in BPA vs. Generation Level Change in the Rest of the WI

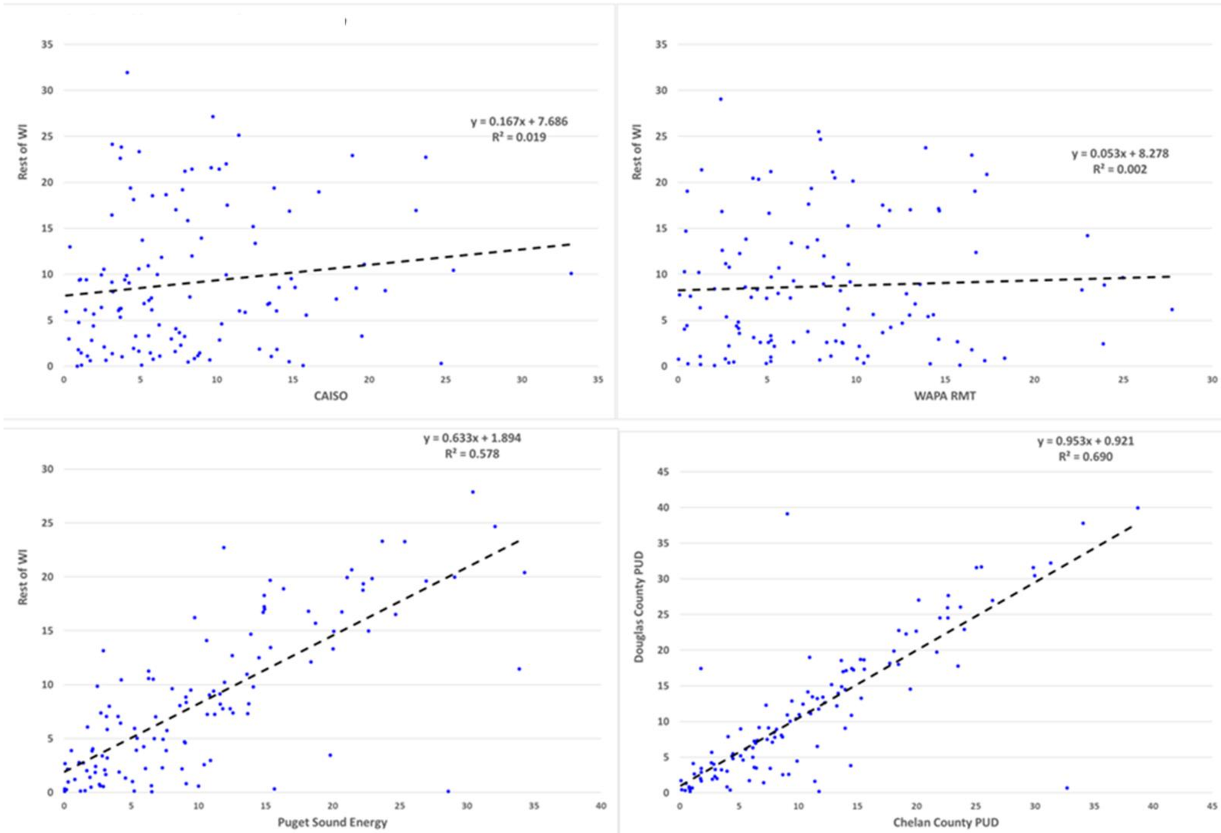


Figure 4-20 Normalized Generation Change between Consecutive Months (GWh) in the WECC vs. Generation Change in the Rest of the United States

Various Pairs of BAs within the WI

The diversity between BAs' monthly generation patterns within the WI is also illustrated by the broad spectrum of their normalized exceedance probability curves in Figure 4-21. Two extreme cases can be identified: the exceedance probability curves of Turlock Irrigation District, at the bottom, and Douglas County Public Utility District (Douglas County PUD), at the top.

The monthly generation level at Douglas County PUD exhibits a flatter behavior, whereas the monthly generation level at Turlock Irrigation District is much more volatile. Figure 4-22 illustrates the normalized generation distribution of these two BAs. The two BAs exhibit complementary distribution patterns, which confirm the still-significant diversity of generation profiles within the WI.

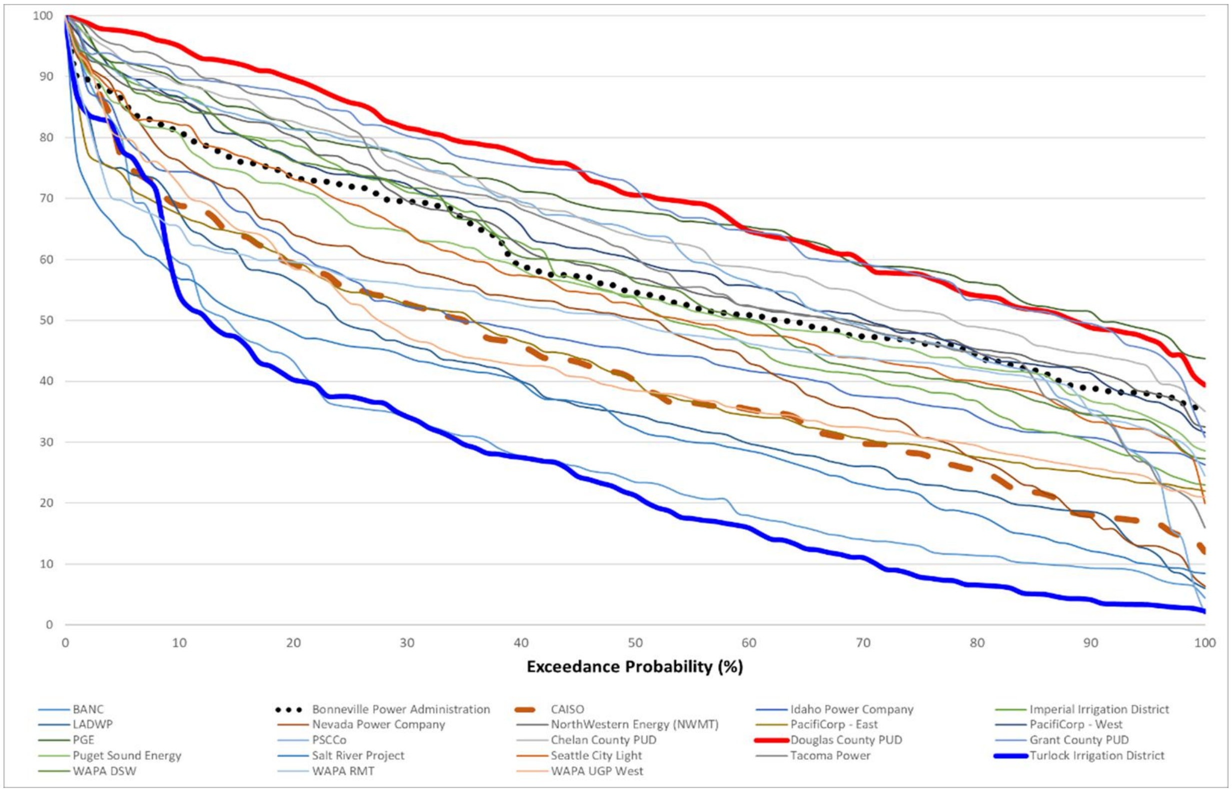


Figure 4-21 Normalized Exceedance Curves of the BA in the WI

The diversity of BA generation profiles within WECC has beneficial consequences on the aggregated monthly generation range. As depicted in Figure 4-23, the sum of the individual minimum monthly generation levels at the BA level over the 2007–2016 period is 7,333 GWh, while the minimum monthly generation level over the entire WI is 9,201 GWh (25% higher). That is, the minimum generation level of the combined set of all BAs in the WECC is much higher than the sum of their individual minimum generation levels, which tend to occur at different times.

On the other hand, the sum of individual BA maximum generation levels in WECC is 26,621 GWh; that is, about 9% higher than the maximum generation level of the combined set of all BAs in the WECC (24,160 GWh). Therefore, diversity results in an aggregated WECC generation profile that has less volatility than the sum of its individual BA components.

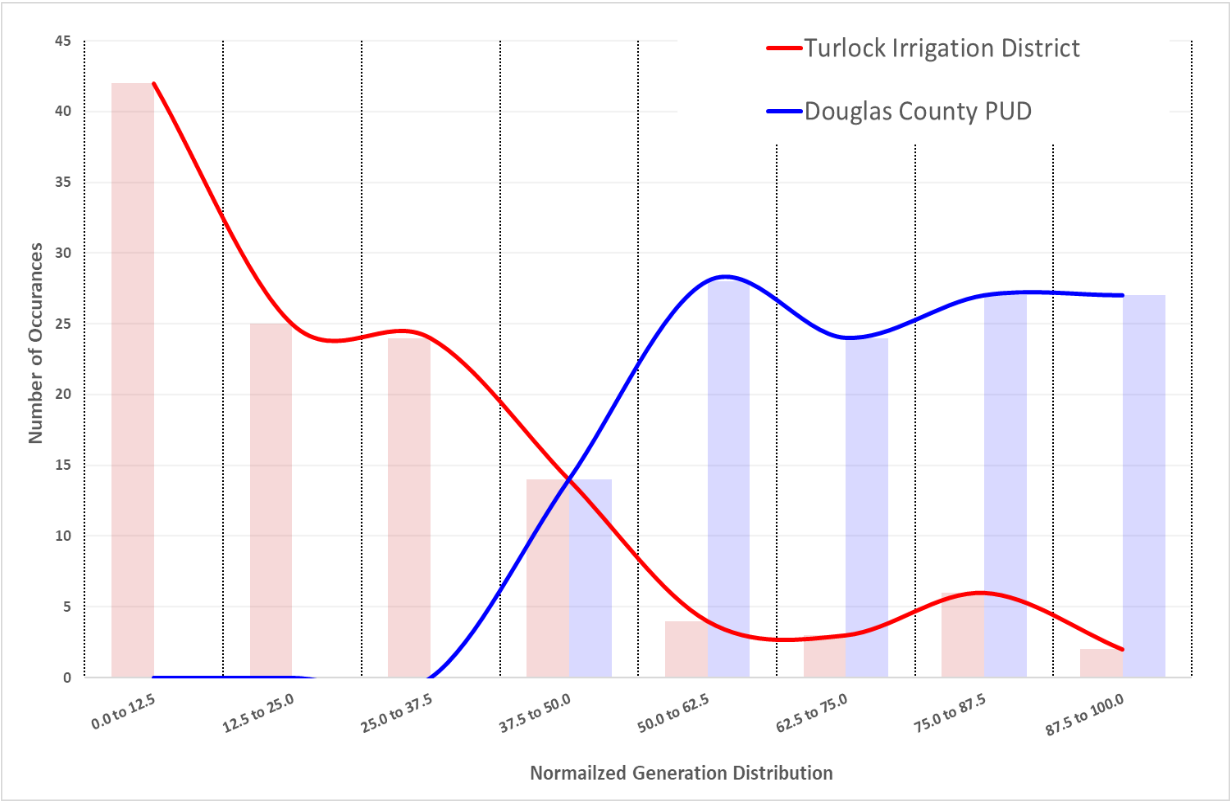


Figure 4-22 Normalized Generation Distribution of Turlock Irrigation District and Douglas County PUD

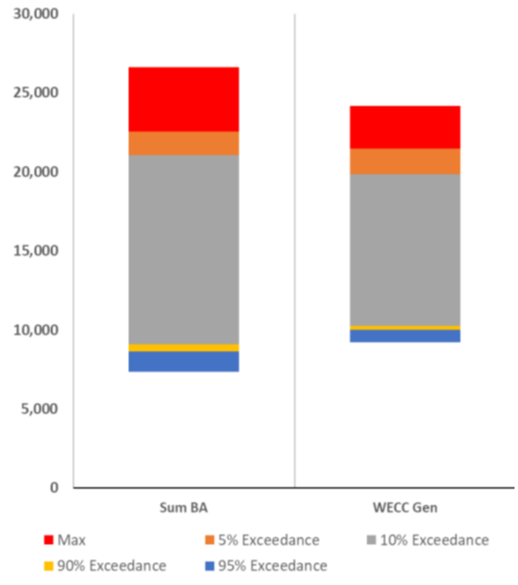


Figure 4-23 Generation Range: Sum of Individual BAs from WECC vs. WECC

4.3 Hydropower Energy Value

Although hydropower plants have a marginal production cost that is near zero, it is not always dispatched because it uses a scarce "fuel"/energy resource (i.e., flowing water). Because of this water limitation, hydropower energy value is maximized when it uses this scarce resource for energy production during times when electricity production by the next-best alternative supply resource is relatively expensive. In other words, U.S. hydropower generation has economic value because it displaces the energy that would otherwise have been produced by more expensive resources in the grid. It thereby reduces total grid generation costs. For example, fuel expenditures and variable O&M costs are not incurred when a hydropower energy displaces energy that would have otherwise been produced by a thermal plant. Marginal system costs are also reduced.

Figure 4-24 shows a hypothetical grid-level power supply curve that represents the cost of energy production. This curve is constructed by ordering generating units by their production cost so that the least expensive unit is dispatched first, and the most expensive unit is utilized last. If the hydropower plant was not producing energy, then the price of energy would be determined by the upper bound price shown on the figure (marginal price without hydro). In this example, the price is based on the marginal production cost of the most expensive unit that operates to serve load.

On the other hand, when hydropower operates, its production serves load that would have otherwise been served by a more expensive (higher cost) thermal generating unit and partially by the next cheapest unit. Because the more expensive unit is not utilized when hydropower operates, the marginal production cost is set by a lower cost generating unit (i.e., marginal price with hydro). The economic value of the hydropower energy production in terms of dollars per megawatt-hour ($/MWh) is the generation-weighted-average production cost of the displaced generation. In Figure 4-24, it lies exactly in the middle of the higher and lower prices because it equally displaces generation from the two units.

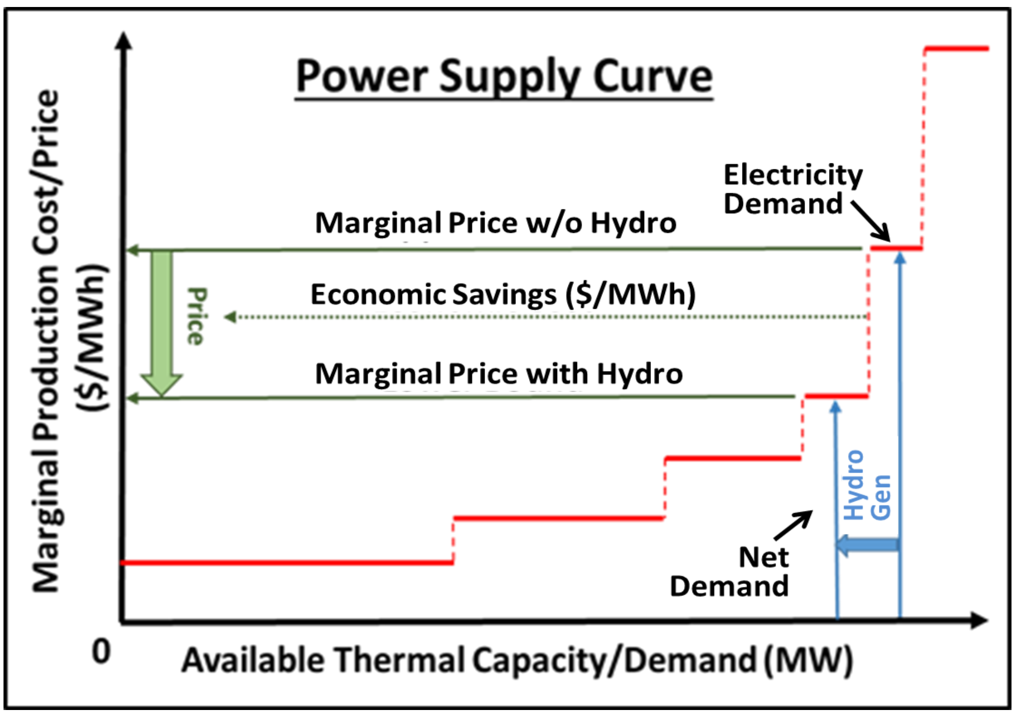


Figure 4-24 Simplified Power Supply Curve Illustrating Hydropower Energy Displacement and Marginal Cost Impacts

Because a supply curve such as the one in Figure 4-24 is usually concave trending upward, the marginal production cost savings from hydropower production is typically relatively low when demand is low, and its value increases at a higher rate with higher loads. In addition, for a fixed load level, the incremental value of additional hydropower production decreases because it replaces less-costly generation.

Hydropower production does not always benefit the grid. For example, in oversupply situations that require thermal unit shutdowns and subsequent expensive restarts, hydropower production may exacerbate the oversupply. These oversupply situations are reflected in the market as negative LMPs, which signal schedulers/dispatchers to back down hydropower generation. At times, this may not be possible due to a lack of operator control or because of environmental operating criteria.

Some economic studies compute the economic value of hydropower energy by multiplying hydropower generation by energy market prices on an hourly basis; these prices are used as a surrogate for grid marginal production costs. Hourly economics are then summed over a study period and discounted to a specified year to compute the total NPV of hydropower energy resources. This approach assumes that prices are "fixed" regardless of hydropower operations.

As illustrated in Figure 4-24, however, in theory the marginal value/price of energy changes in reaction to hydropower production levels. If the operation of hydropower units has a significant impact on market prices, then the market value of hydropower estimated using this approach tends to be overstated. However, this overestimate of value may be relatively insignificant when the hydropower unit(s) under investigation have a very small generation capacity relative to the total generation capacity of the interconnection they reside in, and when the supply curve is relatively flat; that is, economic value reactions to hydropower production are small.

The economic value of hydropower production is zero when its production level does not reduce system-level production costs (i.e., if hydropower generation displaces wind or solar generation). It is negative when hydropower generation increases system-level costs (i.e., when its production requires an expensive shutdown and restart of a baseload thermal unit).

Typically, incremental hydropower production costs are practically nil. Assuming unlimited water resources, hydropower units would almost always be dispatched at the operational maximum. However, water inflow that is required for hydropower production is a scarce resource. The timing of water releases for power production is therefore important. Within water and power operational bounds, transmission restrictions, and environmental/institutional constraints, the value of this limited energy is maximized by displacing the most expensive generation, ancillary services, and/or DSM resources in the grid.

Figure 4-25 illustrates the best use of scarce water resources using a technique known as peak shaving. Limited daily water releases are routed through a 150-MW power plant to produce 1,910 MWh of energy. In order to estimate the daily generation level, an average daily water-to-power conversion factor is used.

In this example, the plant operation satisfies a minimum power production level of 50 MW, which amounts to 1,200 MWh of energy production. This minimum is based on the slowest water flow rate that is required to maintain critical downstream environmental habitats, to satisfy water delivery obligations, and so forth. The remaining 710 MWh of "discretionary" energy resources are used to minimize the peak net load (load minus hydropower production) within the hydropower plants capacity limits.

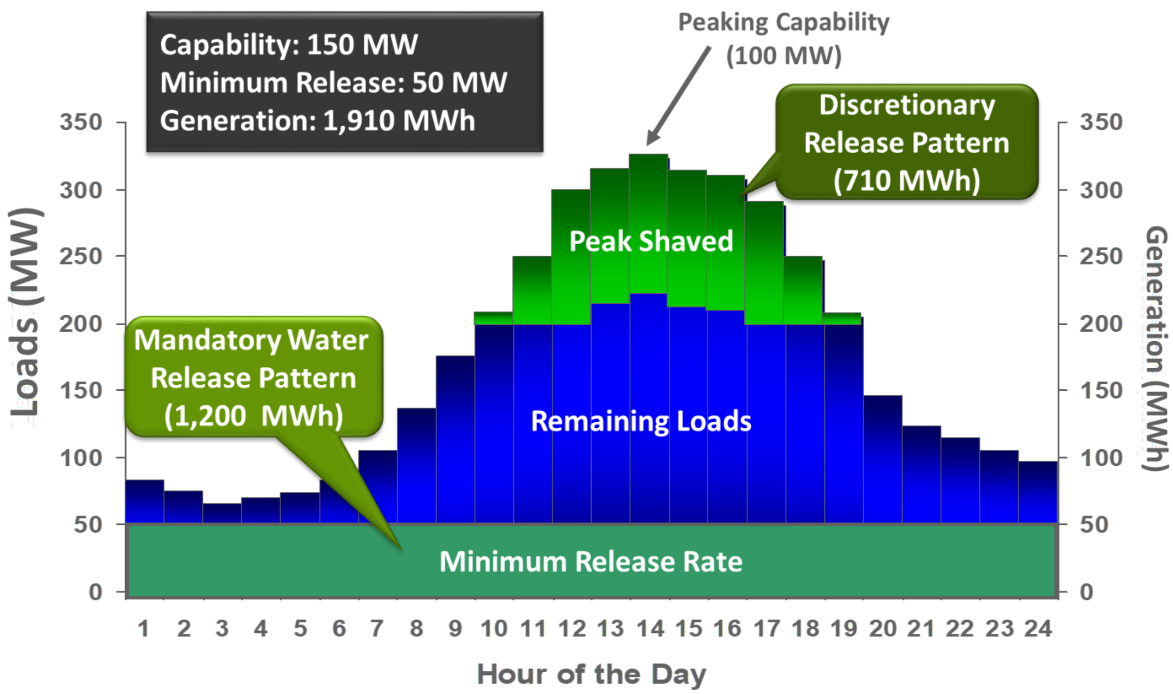


Figure 4-25 Maximizing the Dispatch of Limited Hydropower Energy Resources

This peak-shaving approach implicitly assumes that dispatches of other supply resources in the grid are based on a convex upward price curve such as the one shown in Figure 4-24; that is, marginal prices increase as a function of higher loads. Therefore, by minimizing the largest net load with hydropower generation (i.e., load – hydropower production) via peak shaving, system production cost savings are implicitly maximized because generation from the most expensive units in the system are displaced (i.e., avoided).

A supply curve can be used to compute both system-level production costs and marginal energy values for each hour of the day for the original load profile (before peak shaving). Similarly, the supply curve can be used to compute the economic value of the generation after peak shaving. Production cost differences between the two sets of computations yield an approximation of the value of hydropower energy production. In addition, an examination of marginal energy values shows the impact of hydropower generation on energy market prices. Assuming a convex supply curve, hydropower operations lower prices the most during on-peak hours because hydropower generation is the highest during these hours and the supply curve is relatively steep at high load levels.

A similar technique can be used to estimate the marginal value of water over periods longer than one dispatch interval. For example, if hydropower generation in Figure 4-25 increased from 1,910 MWh to 1,911 MWh, then the additional megawatt-hours of power production would be used to increase generation in the less valuable "shoulder" hours (i.e., hours 10–12 and 17–19) because hydropower output during the peak hours of 13–16 is at the maximum operable level. Because the peak-shaving method indirectly uses discretionary energy when it has the most value, the incremental value of additional hydropower energy decreases as a function of increasing discretionary energy levels.

Although the concepts described above are theoretically sound, in reality there are many complicating factors involved in actual system operations that should be incorporated into hydropower economic evaluations (i.e., avoided cost calculations). Some complicating factors include, but are not limited to:

1. Transmission constraints that frequently require units to be dispatched out of merit order (i.e., low to highest production cost);
2. Reservoir limitations and environmental operating criteria that restrict hydropower plant operations;
3. VERs such as wind and solar—which are also very low-cost producers—also serve some of the load, and their timing is uncertain;
4. Unit technical minimum generation levels, ramping constraints, startup costs, and minimum down times;
5. System reliability criteria such as spinning and non-spinning reserve requirements;
6. Regulation reserve requirements;
7. Other value options for using hydropower peaking capacity for regulation services, and/or contingency reserves instead of serving system peak loads; and
8. Alternative opportunities for keeping loads and generation resources in balance such as DSM initiative.

Any costs incurred from hydropower operation due to an altered dispatch and unit commitment schedule, such as unit operations at lower efficiency points and startup costs, are also factored into the economic value equation. For example, when a thermal unit changes its operating level, its efficiency is also affected. Thermal generating unit efficiency as described by a heat-rate curve typically reaches its most efficient point at full-load operation. Therefore, if the grid supply curve (e.g., Figure 4-24) is simply based on thermal production cost at full load, then using only the curve to compute economic saving from hydropower production will at times result in an overestimate. For example, when hydropower partially reduces generation from a thermal unit, the unit operates at a lower efficiency point. Per megawatt-hour of energy produced, it therefore consumes more fuel and cost more than the amount described by the supply curve.

However, there are other counter situations when the use of the supply curve underestimates the value of hydropower energy (e.g., when the removal of hydropower increases the operating point and therefore the operation efficiency of a thermal units). In either case, the impact of hydropower energy production on the thermal unit operation set point affects grid efficiency, economics, and marginal production cost/prices.

4.4 Hydropower Water-to-Power Conversion Efficiency

The efficiency of a hydropower unit at converting limited water resources into electricity primarily depends on the hydraulic head and the turbine water flow rate. As shown in Figure 4-26, the water-to-power conversion factor, and thus the economic value of water, increases with higher hydraulic heads. It also shows that, as the turbine water flow rate increases from 0% to about 85% of its maximum value, the conversion factor increases. For higher turbine water flow rates, however, the conversion factor decreases with increasing turbine flow rates. In this example, at high heads the potential maximum output of the plant is constrained by generator limitations. However, as the head decreases, the maximum turbine flow rate declines and potential maximum output cannot be achieved.

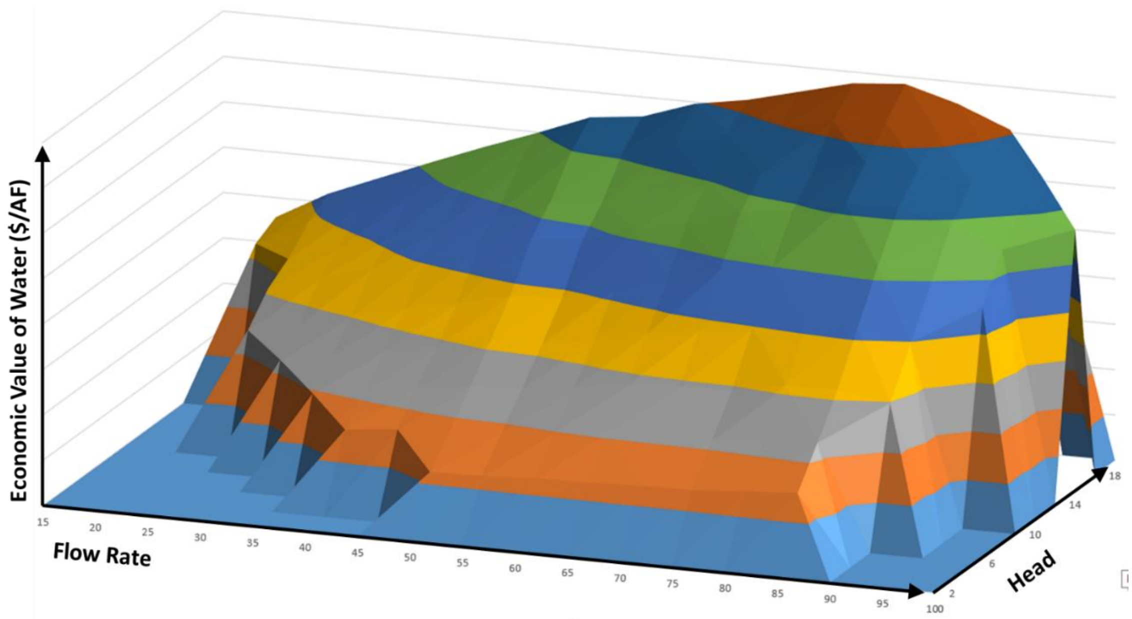


Figure 4-26 Economic Value of Water as a Function of Hydraulic Head and Turbine Flow Rate

In general, thermal power plants such as coal or natural gas power plants are more efficient when they generate more power. In other words, the more power they generate, the less fuel they consume per unit of energy produced. For this reason, it is often economically beneficial for thermal power plants to produce at maximum capacity. In contrast, the maximum power conversion efficiency for a turbine is typically reached at a water release rate that is always less than the maximum possible water release rate. Therefore, to maximize the amount of power that is produced from the release of limited water resources, the hydropower output is set to about 80% to 90% of the power plant maximum operational capacity. This may not be the most economically efficient use of limited water resources because energy production has the highest value during peak hours. Therefore, both system marginal costs and power conversion efficiency should be considered when optimizing hydropower operations.

Because hydropower plant efficiency is not constant, the peak shaving algorithm depicted in Figure 4-25 only yields a rough approximation of the optimal dispatch of a hydropower plant. The peak-shaving algorithm assumes a set amount of energy production over a 24-hour period based on an assumed daily average water-to-power conversion factor that is made prior to a peak-shave simulation. An improvement to the peak-shaving approach is to first compute power production for the given mandatory minimum release and then make an initial assumption regarding the average daily water-to-power conversion efficiency for the discretionary energy. An iterative technique can then be used to estimate the average daily water-to-power conversion efficiency that is consistent with the total discretionary energy production.

Although consistent, an iterative approach does not necessarily yield the optimal solution. For example, the discretionary energy level during hour 10 in Figure 4-25 is small and produced at a relatively low efficiency point. By shifting this small energy production in the next hour (i.e., hour 11), overall daily conversion efficiency would increase, outweighing the revenue lost due to a slightly lower marginal value/price in hour 11. That is, after the reassignment of hour 10 energy to hour 11, the net load in hour 11 will be lower than in hour 10, resulting in a slightly higher marginal energy value in hour 10. That is, there is a tradeoff between the marginal increase in conversion efficiency/water use and the marginal increase in grid value over specific dispatch scheduling period (e.g., a day).

In addition to the impact of scheduling hourly/sub-hourly generation for a unit at a hydropower plant, there are interdependencies among units that are located at the same plant. For example, if a single unit is operating at its maximum efficiency, the loading of a second identical unit also at its maximum efficiency will increase the tailwater or afterbay elevation below the plant, thereby reducing the hydraulic head and overall efficiency of the hydropower plant. That is, the unit that was initially operating alone will have a lower water-to-power conversion efficiency after the second unit is loaded. For example, Figure 4-27 shows the tailwater elevation at the base of the dam as a function of water release rate from the Morrow Point (MP) reservoir located on the Gunnison River in Colorado. Supervisory control and data acquisition (SCADA) data from April 1, 2009, through September 30, 2009, were used to construct the tailwater elevation curve. Because of the interactions between turbine water releases, including the raising of the tailwater elevation at the two MP units, efficiency is affected. Figure 4-28 shows that during April 2009 the maximum power conversion factor decreased slightly when both units operated at the same time (green line) relative to the maximum observed conversion factor when both units operate at different times (blue and orange lines).

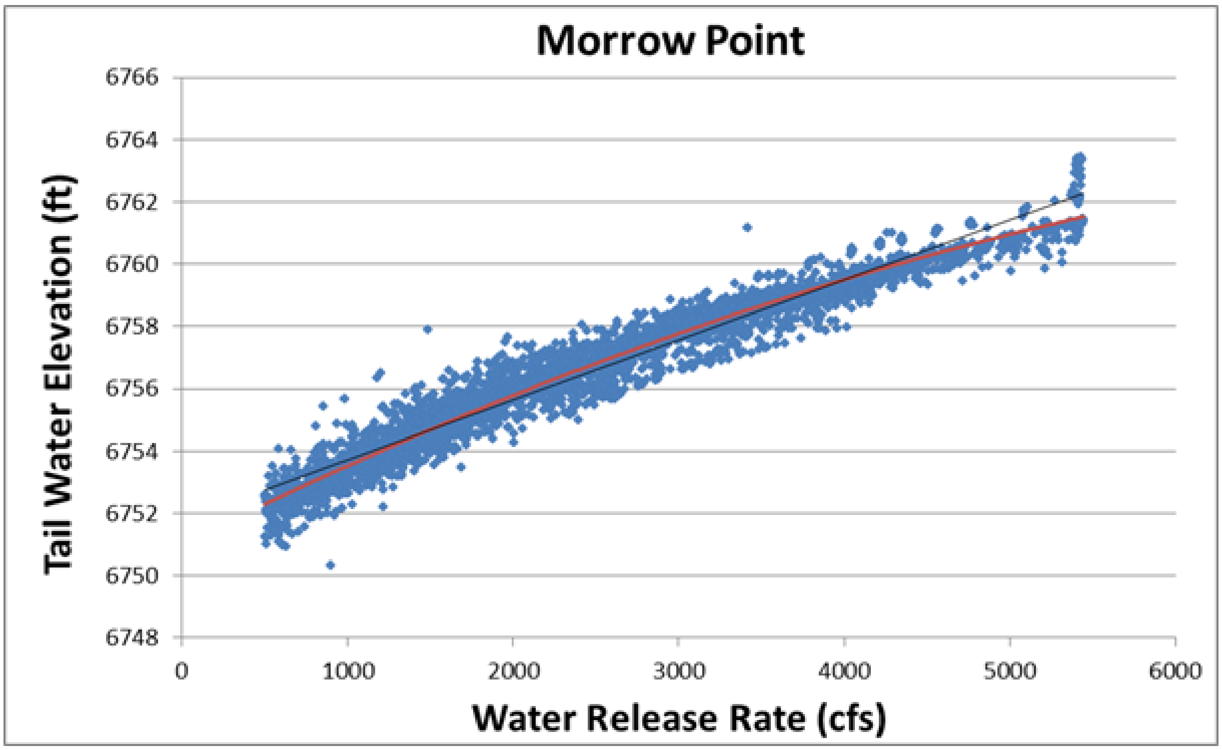


Figure 4-27 MP Tailwater Elevation as a Function of Water Release Rate

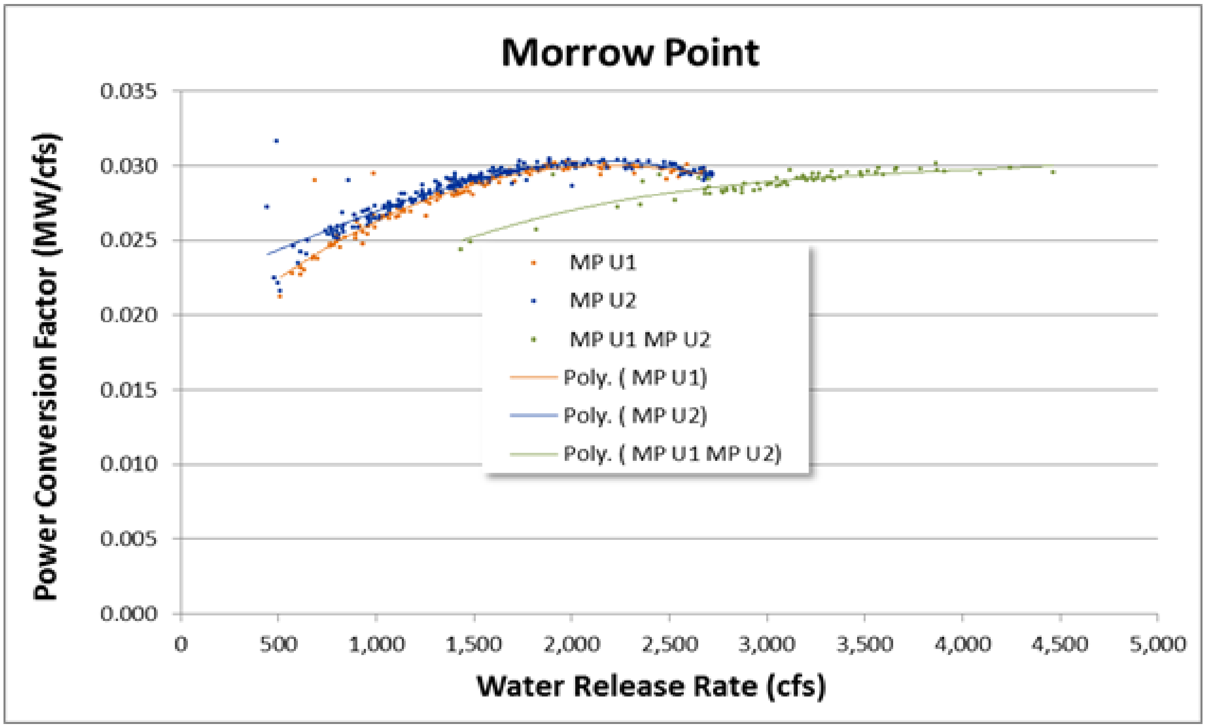


Figure 4-28 MP Hydropower Plant Power Conversion Factor as a Function of Water Release Rate, April 2009

4.5 ROR Hydropower Plant Conversion Efficiency

ROR hydropower plants are non-dispatchable supply resources that rely solely on river/channel flow rates to produce power. These flows are either uncontrolled/based on natural hydrological events, or controlled by an upstream reservoir (a.k.a., upstream ROR peaking), or a combination of both. Unlike hydropower plants with a reservoir, ROR hydropower plants have no ability to store water inflows for later releases; water outflows are identical to water inflows. Because of this, ROR plants can only produce electricity when inflows occur. However, due to turbine efficiency characteristics and the impacts of tailwater elevation, the amount of electricity produced is not necessarily proportional to the amount of water inflows.

Figure 4-29 shows an aerial view of the ROR Gem State Hydropower Plant located on the Snake River near Idaho Falls, Idaho, and the location of a gauge that measures water flow rates downstream of the plant. A scatter plot of electricity production and water gauge flow rates is shown in Figure 4-30. The powerplant electricity production/flow curve exhibits two distinct patterns. When the river's flow rate is between 2,000 and 7,000 cfs, the power produced by Gem State is roughly proportional to the flow rate, with an average power conversion factor approximately equal to 3.6 W/cfs. However, when the river's water flow rate is above 7,000 cfs, the amount of electricity produced by the Gem State hydropower plant decreases as the water flow at the gauge becomes faster; that is, an increase in the water flow rate decreases power production by about 0.2 watts. This phenomenon is due to the decreasing hydraulic head under high flow rates. Very high flow rates increase the afterbay elevation level, thus decreasing the hydraulic head, and a lower hydraulic head significantly reduces the efficiency of the water-to-power conversion.

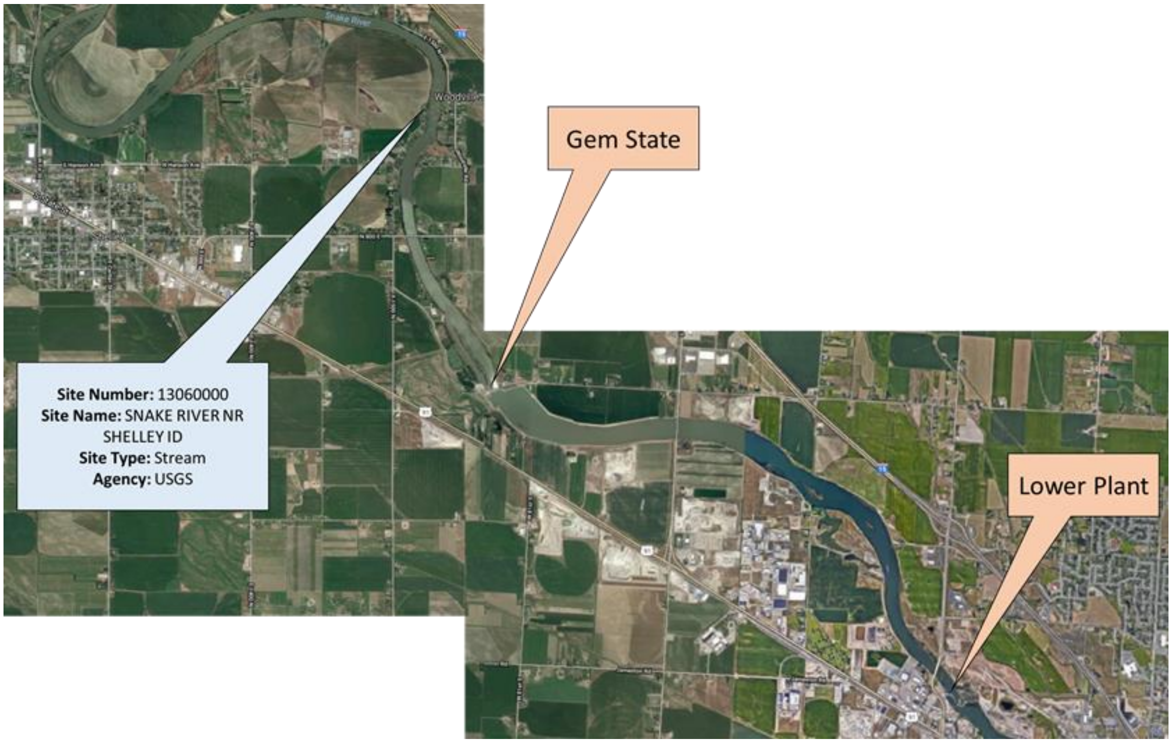


Figure 4-29 Aerial View of ROR Gem State Hydropower Plant and Snake River Gauge

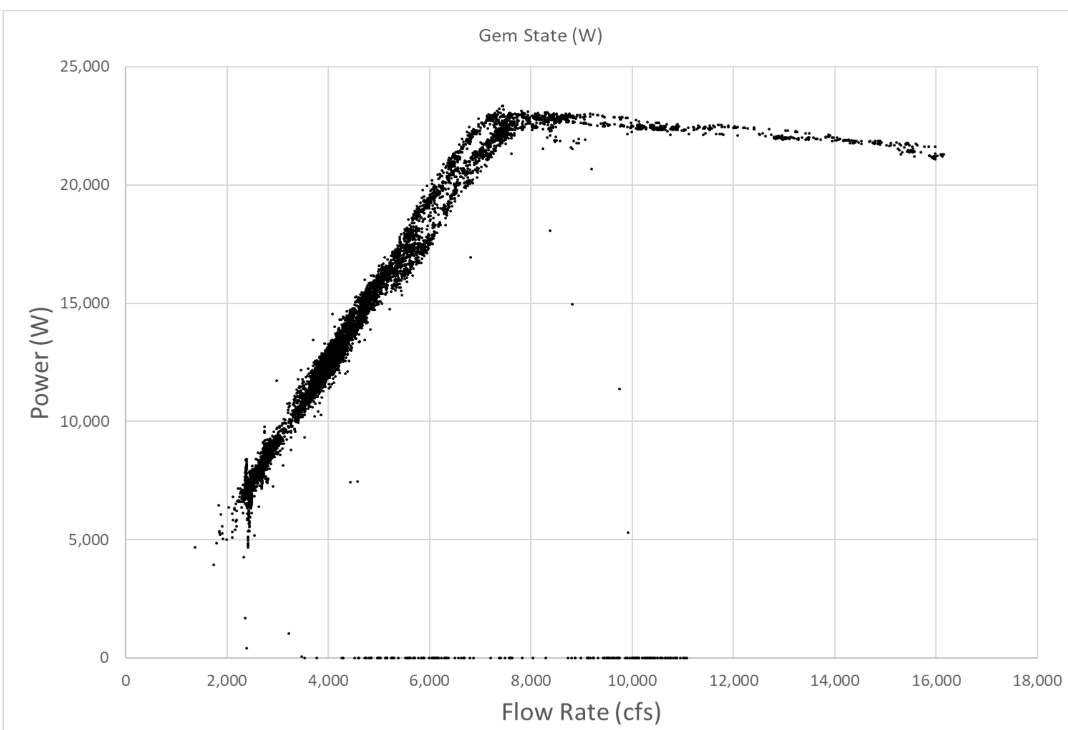


Figure 4-30 Power Produced at Gem State vs. Flow Rate Measured at Snake River Gauge

The incremental value of water above the maximum turbine flow rate is negative, because each additional increment of water flow decreases power production. However, the positive impact is that it reduces the volatility of power production. Figure 4-31 and Figure 4-32 illustrate the latter point. Figure 4-31 represents five flow rate profiles in July at the Snake River Gauge for from 2011 to 2015. Note that July 2011 (black line) was a very wet month with unusually high flows. Because the plant is capacity limited, high flows did not lead to higher production levels. Instead, Figure 4-32 shows that these unusually high flows led to production levels that were only slightly below production levels in other years with lower flow rates. This is a direct consequence of the water-to-power conversion curve illustrated in Figure 4-30, which shows that water flow rates greater than 7,000 cfs produce lower energy levels.

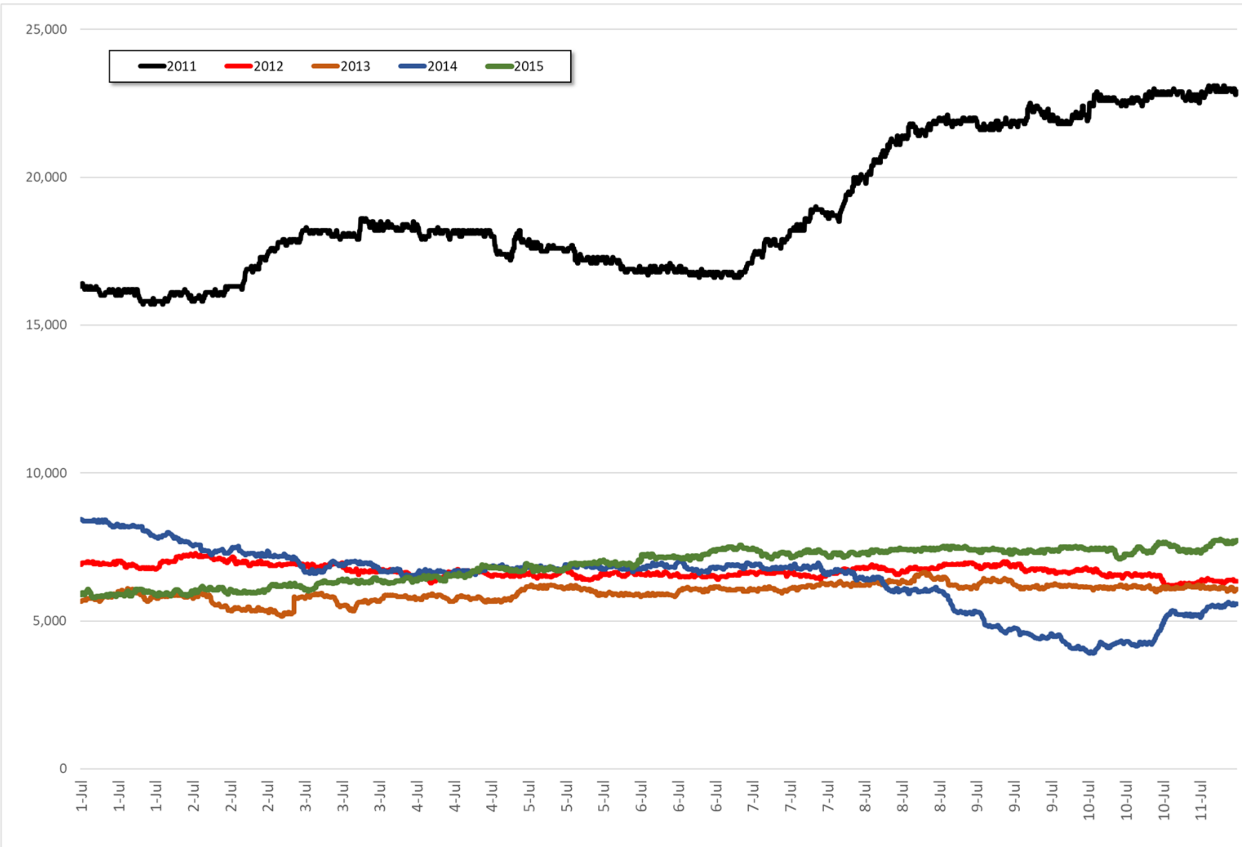


Figure 4-31 July Flow Rate (cfs) Profiles at Snake River Gauge, 2011–2015

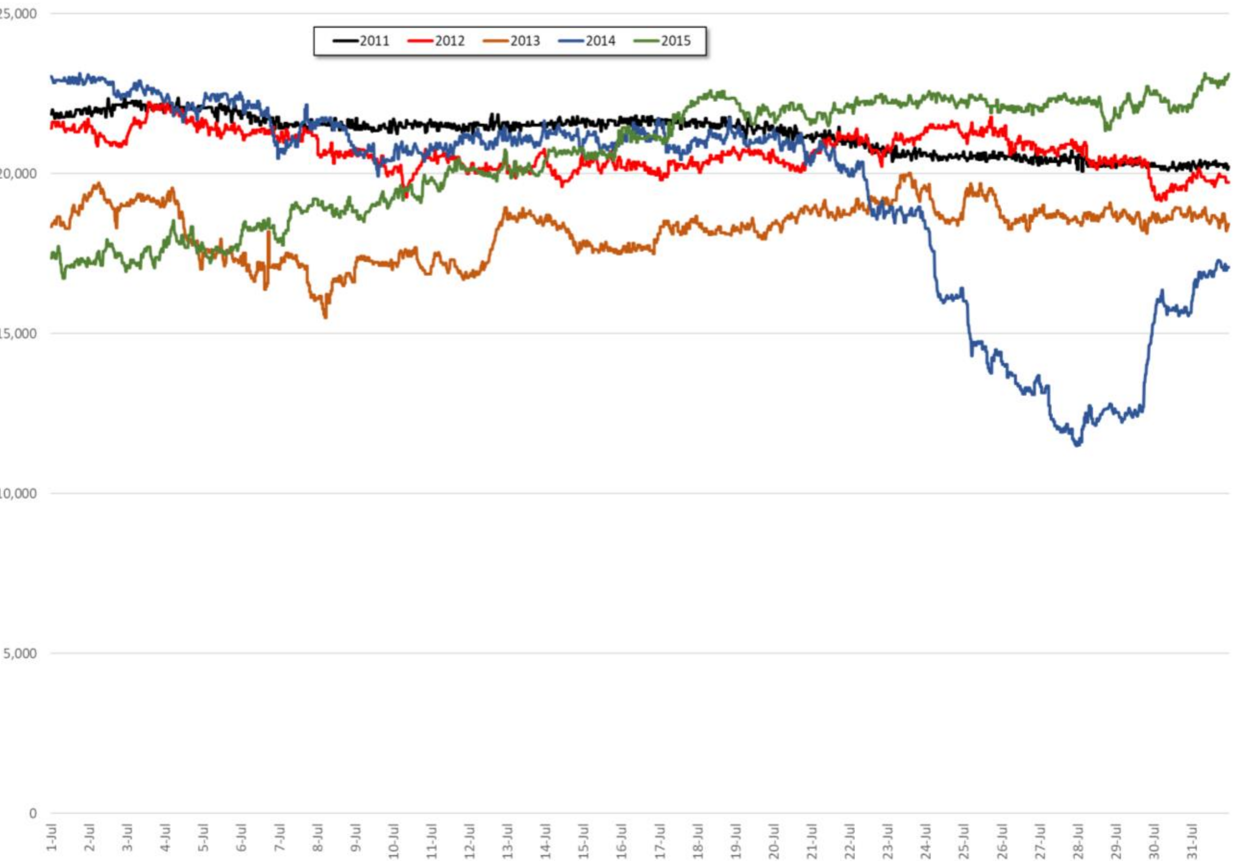


Figure 4-32 July Power Production (W) Profiles at Gem State, 2011–2015

5.0 Value of Reservoir Water Storage

Both peaking and intermediate hydropower plants have a powerhouse that is located very near to the dam that stores water in a reservoir. Within physical and institutional limits, reservoir water storage allows operators to control water releases through hydropower plant turbines at levels that differ from inflows; that is, power plant generation can be dispatched. If Gem State operators had been able to store water in a reservoir, water releases would have been scheduled essentially at the times when the power conversion factor was the highest and when the water was the most valuable. That is, a higher fraction of the water would have been released during times of high prices.

When reservoir outflows are less than inflows,[40] the reservoir elevation increases. On the other hand, the elevation decreases when outflows are greater than inflows. Reservoirs are therefore used to shape water release/generation profiles to meet specific utility/owner objectives, such as maximizing net revenue, maximizing economic value, and/or following/peak-shaving loads. Water release "shaping" over time at many plants is subject to several constraints, such as reservoir storage limitations, water delivery obligations, and environmental operating criteria. In general, the larger the active reservoir storage, the longer the potential reshaping timeframes—ranging from a few minutes to multiple years. Hydropower economic value tends to increase as a function of long-term water release controllability and flexibility because it allows for higher levels of both available energy and operational maximum potential when it has a higher grid value. Reservoir water storage also reduces both generation uncertainty and volatility, which also adds to its economic value.

The left side of Figure 5-1 is a generic depiction of a typical reservoir elevation-storage volume curve. The shape of the curve varies significantly among reservoirs, as dictated by the contours of the reservoir topology. Reservoirs that are box-shaped (topology with very steep slopes/cliffs with a flat floor) have a relatively small curvature (closer to a straight line – zero/small second derivative), while v-shaped topologies have a larger concave-down curvature.

The shape of the reservoir affects power productions and therefore economic value because it influences the conversion efficiency of water turbine releases to energy production. Typically, at low reservoir storage levels, a change in water storage results in a fairly large increase in the forebay water surface elevation (i.e., the curve has a relatively steep slope). In contract, under high reservoir elevation conditions, a change in reservoir storage volume results in a relatively low change in forebay elevation. Therefore, adding to water storage at low reservoir elevations tends to increase the water-to-power conversion efficiency proportionally greater than adding water to storage when the reservoir elevation is high (i.e., near capacity). This relationship highlights the tradeoff between releasing water now for energy production, thereby lowering the reservoir elevation, or releasing the water at a later point in time when presumably future inflows will increase the reservoir elevation and therefore the power conversion efficiency.

The right side of the Figure 5-1 shows that a reservoir must operate within elevation limitations that translate into storage volume limitations. Operators typically do not operate at these limits because projections of future inflows are subject to error that may trigger either expensive real-time adjustments or a rule violation. For example, if the reservoir is at the maximum elevation level, a higher-than-projected inflow would require the operator either to increase turbine flows, resulting in generation levels

[40] In this context, inflows include any water sources that are input into a reservoir, including contributions from a main river channel, side flows, ground water, precipitation, and so forth. Outflows include water that exits the reservoir, including releases via turbines, bypass, and spillways; direct withdrawals; ground seepage; evaporation; and so forth.

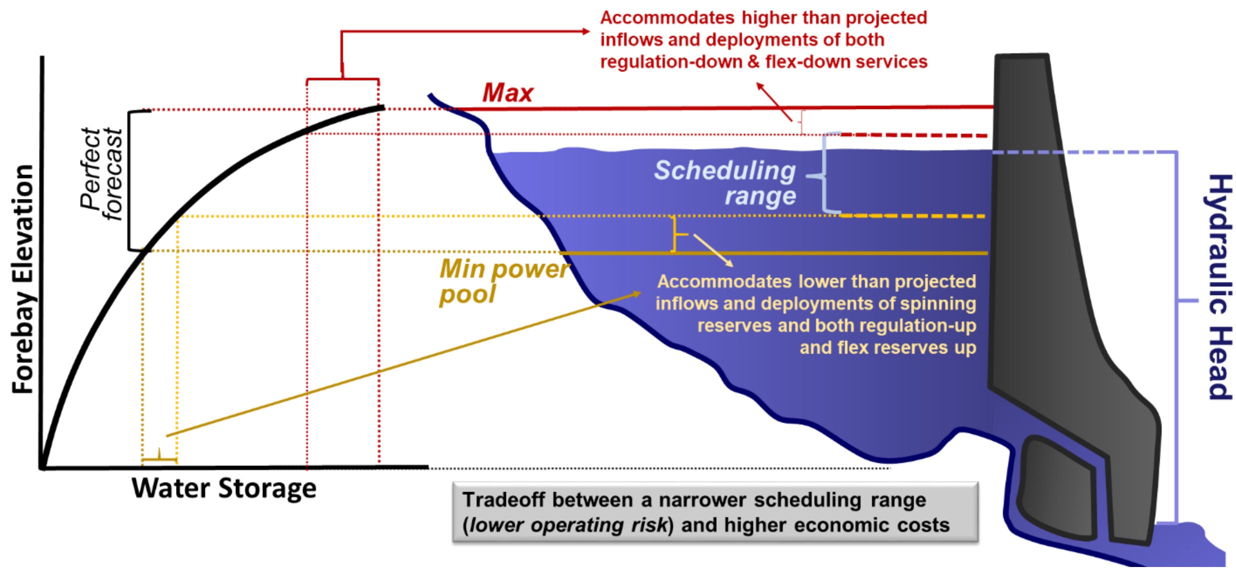


Figure 5-1 Generic Reservoir Storage Volume/Elevation Curve and Water Storage Buffers to Accommodate Inflow Forecast Error

above scheduled levels, or to increase non-turbine water releases via bypass tube(s) or spillway(s). If the scheduled generation were at the operational maximum, then non-power water releases would be the only option to remain within the reservoir maximum limit. There may be situations when the forecast error is very large, in which case the operators may not be able to avoid a violation (i.e., forecast error is greater than spare turbine flow and bypass capabilities).

Similarly, operating the reservoir at the lower elevation limit would require the operator to make real-time adjustments when actual inflows are less than previously forecasted. Either turbine and/or non-power water releases would need to be reduced below scheduled levels or a violation would occur. If the lower limit is set equal to the minimum power pool elevation and a violation occurs, the plant would not be capable of generating electricity until the pool elevation increases above the minimum level.

To reduce the risk of costly real-time adjustments and/or violations, operators either explicitly or implicitly set reservoir high-end and low-end elevation targets that are more restrictive than the mandatory limits. As depicted in Figure 5-1, these elevation targets also translate into a more restrictive range of working storage. Because the shape of a typical water storage volume-to-elevation curve is concave downward, reducing the high reservoir elevation target by a foot to accommodate a higher-than-projected inflow forecast error translates into a larger water buffer than a foot-elevation buffer at a low reservoir elevation. Note in that Figure 5-1 although the high reservoir buffer, in terms of reservoir elevation, is smaller than the lower elevation buffer, the high reservoir water buffer is larger in terms of water volume.

The size of the upper and lower buffers depends on the situation. For example, if operators use persistence forecasting, then the upper-end buffer may be larger on warm days during the spring snow-melt period as compared to days with colder air temperatures (i.e., below freezing). Note that a water release that occurs in the present lowers the reservoir elevation and consequently the water-to-power conversion efficiency in subsequent periods lasting perhaps months or more into the future. The lower efficiency reduces it value because, all other factors held constant, less energy is produced per unit volume of water released.

In addition, the physical maximum output is typically reduced under most elevation levels, which affects its firm capacity credit used in IRP capacity expansion. On the other hand, stored water does not yield value until it is released. One possibility is to always keep the reservoir at the highest allowed level. However, this strategy would require inflows and outflows to always be equal, much like a ROR hydropower plant. Most of the time turbine water release rates would be at a suboptimal efficiency point. Non-power releases would also occur whenever inflows exceeded the sum of the maximum turbine flow rates of all generating units.

Another strategy is to allow for some daily flexibility such that the reservoir is at its maximum storage level during the time of the day that has the lowest demand or energy value. The plant would therefore operate as a daily storage hydropower plant regardless of its storage capabilities. The reservoir, however, would not be able to take full advantage of seasonal energy and ancillary service price patterns.

The optimal economic solution is the one that uses the full reservoir storage capabilities to take advantage of energy and ancillary service on a seasonal/monthly, weekly, and daily basis. If seasonal, daily, hourly and sub-hourly inflow forecasts were perfect, schedulers could take full advantage of the entire reservoir scheduling range (see Figure 5-1), thereby maximizing it economic benefit. Because forecasts are imperfect, however, this benefit is usually not realized, and reservoir buffers are required. Upper and lower buffer sizes are based on the probability distribution of forecast error and the risk tolerance of schedulers. It therefore follows that more accurate reservoir forecasts would increase hydropower economics.

Operations of cascaded hydropower plants are more complex than single plants because scheduling and operation among plants are interdependent. The level of power-plant interdependencies is based on the topology of channel linkages among the plants, the relative size of the cascaded reservoirs/plants, and channel side flows. In general, the closer the reservoirs/plants, the tighter the coupling of the operations. In addition, downstream reservoirs that have less storage are more tightly coupled than larger ones. As depicted in Figure 5-2, operation at the lower reservoir are dependent on releases from the one above it and side flows that feed either directly into the lower reservoir and/or into the channel that connects the two reservoirs.

An example of the relationships among power generation, water releases, and reservoir elevation interdependencies for the Aspinall Hydropower Cascade is shown in Figure 5-3. When BM, located at the top of the cascade, releases more water than MP, the forebay elevation at MP increases (e.g., hour 10), thus improving the power conversion efficiency in subsequent hours. Further, downstream, the Crystal (CY) reservoir elevation is affected by MP generation/releases. Note that CY generations and flows are nearly constant; therefore, when MP does not release water for the first 6 hours of the day, the CY reservoir elevation continuously drops.

In the Aspinall Cascade example, power schedules must be coordinated so that reservoir operational constraints at both reservoirs are not violated. For example, if the CY reservoir is at its maximum level, a high release from MP may result in either non-turbine releases or a violation at CY. This occurs when the water volume received from MP cannot be released through the single CY turbine. The situation is exacerbated by any side flows between MP and CY. In this regard, the coupling of operations decreases the overall value of the MP hydropower plant compared to a case in which MP was not coupled with CY; that is, when cascaded, MP operations are restricted by both MP and CY constraints. On the other hand, MP controls daily and monthly water volumes that CY receives. Therefore, if not for the storage capabilities of BM and MP, CY would frequently receive uncontrolled inflows that exceed the CY maximum turbine rate, thereby increasing the economic value of the CY hydropower plant.

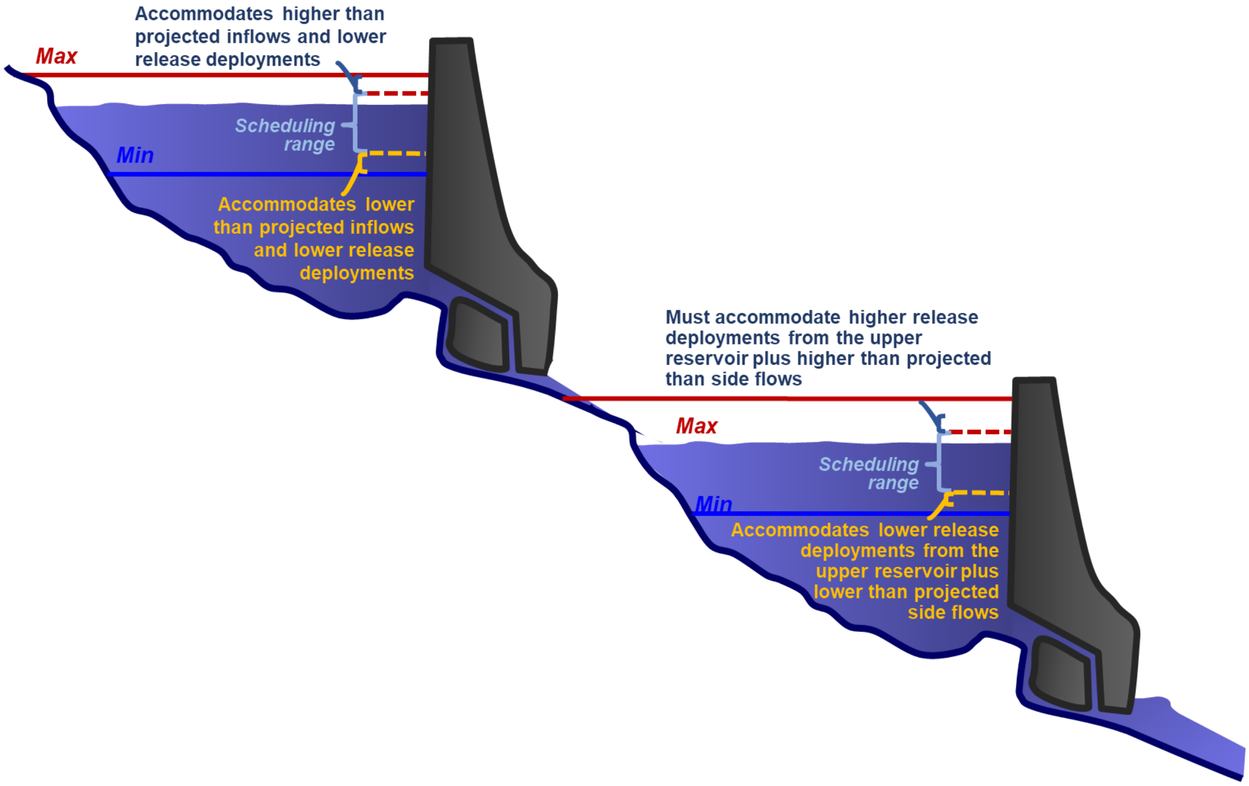


Figure 5-2 Interdependencies among Cascaded Hydropower Plants

Coupled operations are also very advantageous in other situations/topologies. For example, for short-term operations, a ROR hydropower plant that is downstream of a nearby storage plant operates in tandem with the dispatchable upper reservoir. This enables the ROR hydropower plant to follow prices and/or loads in a similar way as a power plant with storage. For longer term operations such as daily, monthly, and seasonal operations, the collective use of water storage among all reservoirs increases the overall value of water. For example, a multiyear water storage reservoir allows a lower reservoir with weekly or daily storage capacities to operate as if it also had multiple years of water storage.

Determining both the timing and rate of reservoir water releases/generation that maximize economic value is very challenging because it is a nonlinear, multifaceted problem. This includes interactions between:

1. Reservoir elevation and turbine-level water-to-power conversion efficiencies as a function of flow rate,
2. Interdependencies between cascaded reservoirs and power plants,
3. Allocation of operational maximum output for different purposes (e.g., energy, ancillary services, flexibility reserves), and
4. Reaction/response functions between hydropower operations and the rest of the grid (e.g., impact on thermal generating unit efficiency).

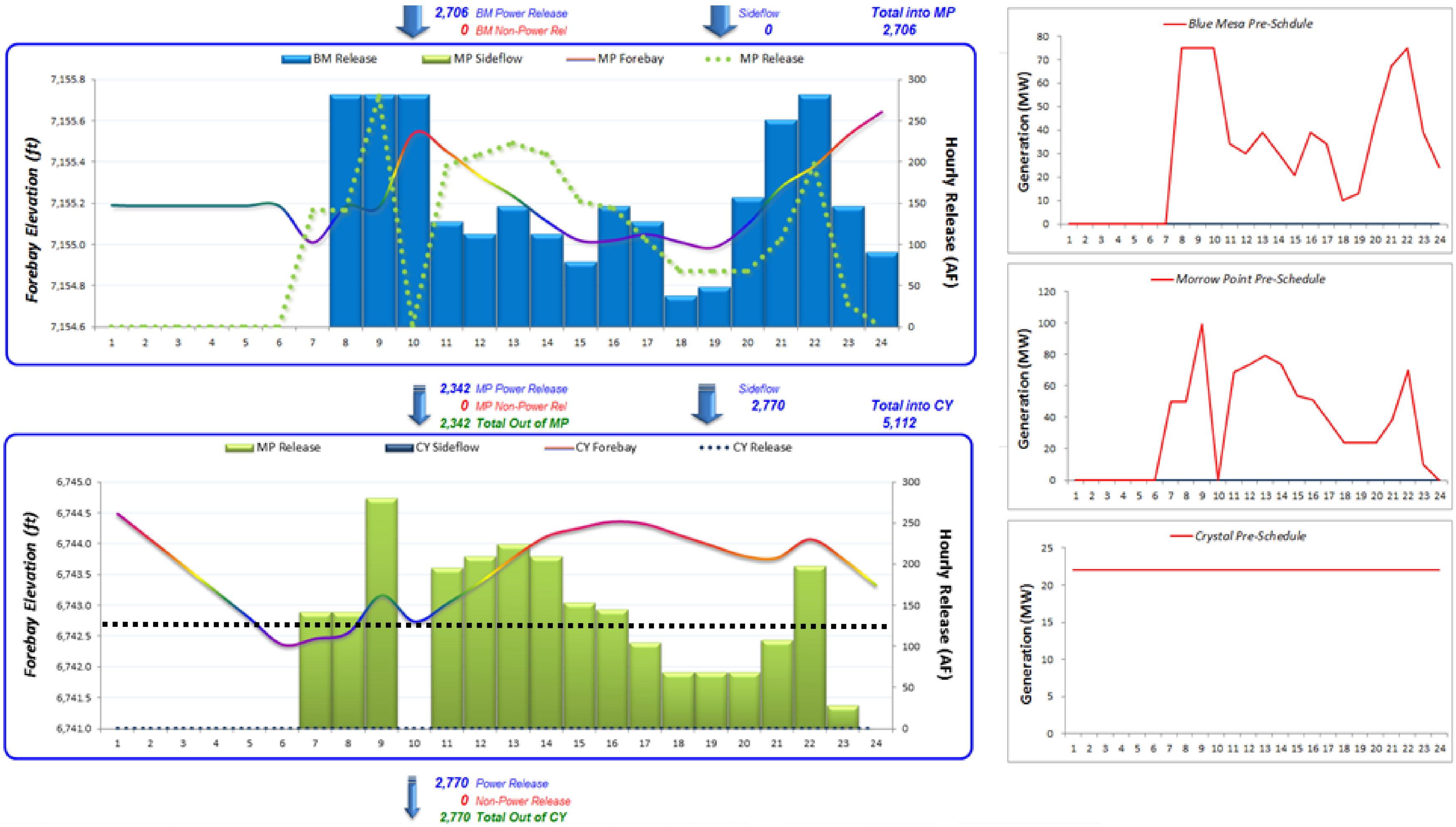


Figure 5-3 Aspinall Cascade Operational Interdependencies

It is further complicated because scheduling decisions are made under uncertainties regarding inflows and grid value vectors over time. Depending on reservoir water storage capacities, the water channel topologies, and water travel times among reservoirs, maximizing the value of water for hydropower plant operations requires coordination on timescales ranging from real-time operations to multiple years. When all of the hydropower and storage resources are owned and operated by the same entity, a single decision maker can schedule operations and dispatch of the system in real time. However, when cascaded hydropower plants are owned by more than one entity, overall maximum economic efficiency may not be realized, because each entity's behavior is driven by its own self-interest, not an overall system economic efficiency objective.

For example, if one entity owns a hydropower with associated reservoir water storage and another entity owns a nearby downstream ROR plant, upper reservoir operations that maximize the financial benefit of the entity that owns it may significantly reduce the economic value of the ROR plant. More specifically, the storage plant may release large amount of water during just a few super-peak hours that have the highest energy market prices. These releases may exceed the maximum turbine rate capacity of the ROR plant, forcing it to make nonpower releases. A nonpower water release not only produces no economic value, it also decreases the value of water that goes through the power plant. The turbine water value is reduced because the nonpower water increases the tailwater elevation below the plant, reducing the amount of power produced. This phenomenon of decreasing ROR output as a function of increasing nonpower water releases was illustrated in Figure 4-30.

Instead of concentrating releases over a short period, overall system economics may be maximized by releasing the daily water volume over a few additional hours such that ROR spills are avoided. These additional release hours may have a lower energy market price compared to the super-peak period, but the economic benefits gained by avoiding spills and increasing generation efficiency at the ROR may far outweigh lower revenues generated by the upper hydropower plant.

6.0 Value of the Reservoir Capacity for Hydropower Plant Operations

Hydropower generation is not only spatially dependent both on the hydrology of basin where the plant resides and interdependencies among basin resources, it is also dependent on the temporal pattern of hydrological conditions. In the northwest region of the United States, for instance, water inflows are generally highest in May and June, and lowest at the end of the summer. Electricity demand, however, follows a very different monthly pattern. Storage capacity provides a high value to hydropower plants because it allows the plants to shift their power production during times of higher energy value. It also allows planners/operators to dampen peak monthly flow volumes and reduce volatility. On a shorter timeframe, such as weekly to hourly scheduling, water storage capacity also provides operational flexibility to schedule power production and use of ancillary services in times when they have the highest value. In contrast, for ROR hydropower plants, outflows and inflows are typically identical.

Figure 6-1 illustrates the average monthly operation of GCD between 1980 and 2018. Assuming that evaporation and groundwater impacts are negligible, the average volume of water inflows in a year is equal to the average volume of water released. However, the monthly patterns of water inflows and water releases clearly differ. In the case of GCD, the variability of monthly inflows depicted by light blue shading, ranging from an average inflow rate of 7,000 to 38,000 cfs, is much higher than the variability of monthly releases (outflow) depicted by the dark blue columns, ranging from 12,000 to 17,000 cfs. This delay/shifting of water release is possible because Lake Powell, the GCD reservoir, stores up to 26 million acre-feet (AF) of water. The high runoff of water inflows in May and June, due to spring snowmelt, is stored for a later release in July and August. Due to environmental constraints, however, not all of the water can be stored, and a small fraction was released in June without producing electricity (nonpower release).

Note that large reservoirs, such as Lake Powell that can store several years of water, provide additional hydropower value. Lake Powell not only stores water because the stored water can be managed to meet demand throughout a single year, but also because stored water can be used to mitigate the negative impacts of prolonged droughts.

GCD's ability to delay and flatten its water release is highlighted by the comparison between the numerous historical inflow and outflow exceedance patterns in Figure 6-2. More than 50% of the time, historical monthly inflow profiles exhibited a large variability, with maximum inflows in June that were at least four times higher than minimum inflows during winter (dark blue line in the middle of the blue area). Despite this, 90% of historical monthly water releases (combined power and nonpower releases) were relatively flat, with peak releases less than 50% higher than minimum releases (red dashed line). Turbine releases are even flatter, thanks to bypass releases (Figure 6-3).

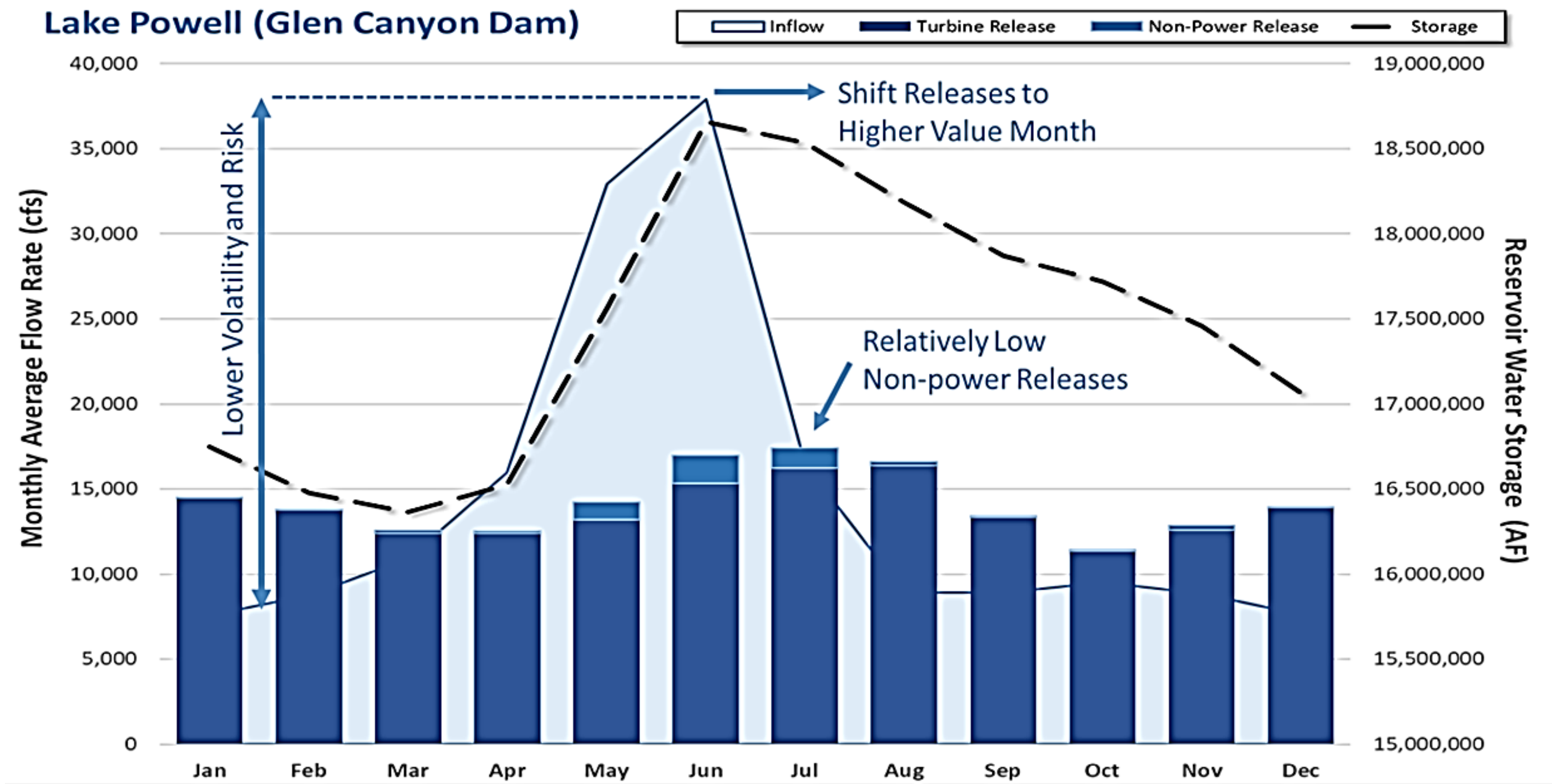


Figure 6-1 Average Monthly Pattern of Inflows, Turbine Releases, Non-power Releases, and Reservoir Storage Levels at GCD

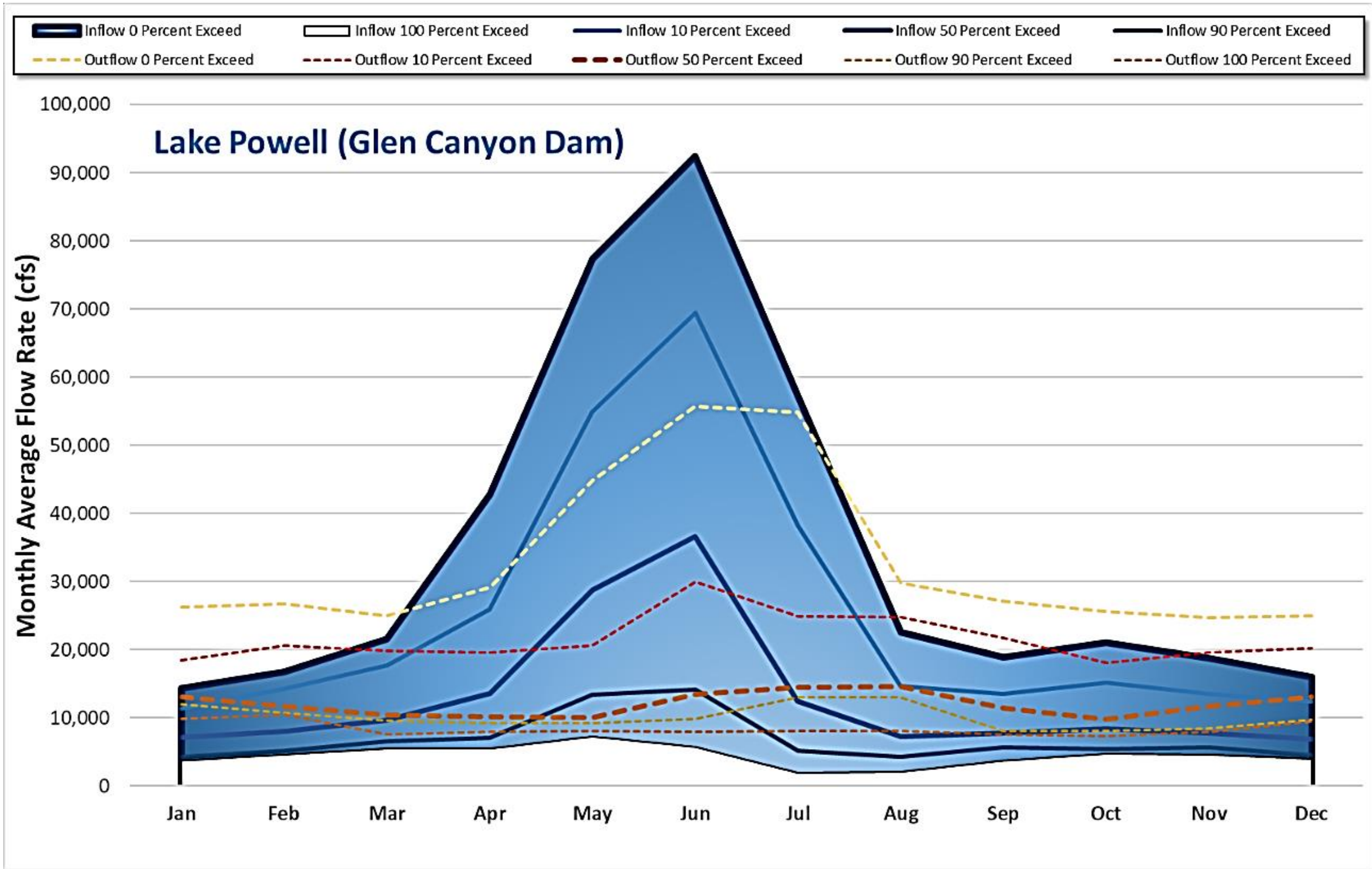


Figure 6-2 Historical Monthly Inflow and Outflow Exceedance Patterns at GCD

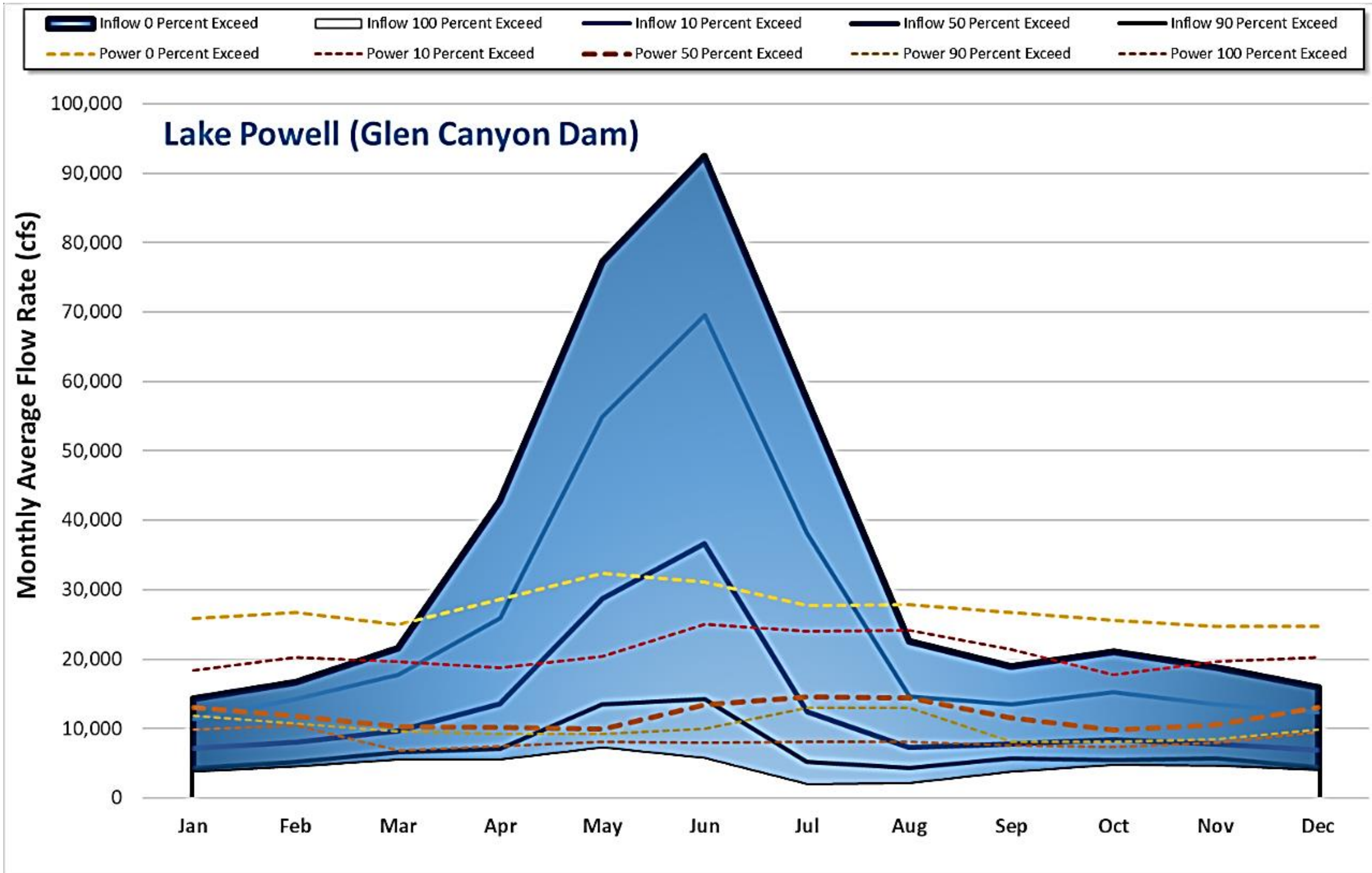


Figure 6-3 Historical Monthly Inflow and Turbine Outflow Patterns at GCD

Hydropower plants with smaller reservoir capacity, such as the one at BM have a lesser ability to reduce the outflow variability. As shown in Figure 6-4, BM has an average flow rate of 1,300 cfs between 1980 and 2018, that is, 10 times lower than the one of GCD, and a storage capacity of only 940 thousand acre-feet; that is, 27 times lower than the one of GCD. Because the ratio of storage capacity to average flow rate for BM is much lower than the one of GCD, BM has a monthly release pattern that follows more closely its monthly inflow pattern. Because of this limited storage capacity, BM has bypassed a larger fraction of its water than GCD in June and July. These non-power releases are typically attributed to snowmelt run-off forecast error that occurs in late spring/early summer; that is, operators did not sufficiently drawdown the reservoir at BM prior to the snowmelt season because it was predicted that inflows would be lower than the amount that actually occurred.

The effects of a small reservoir are even more striking in the case of the Fontenelle (FN) hydropower plant. Figure 6-5 shows an average flow rate similar to the one at BM, but the reservoir storage capacity is around three times smaller. In this case, the monthly inflow and outflow patterns are very similar, with a peak occurring in June in both cases. Because of this, in June, up to one fourth of the outflows is released through bypass tubes instead of being used to produce electricity. For hydropower plants with small reservoir capacity, a significant amount of water value is lost during snowmelt period.

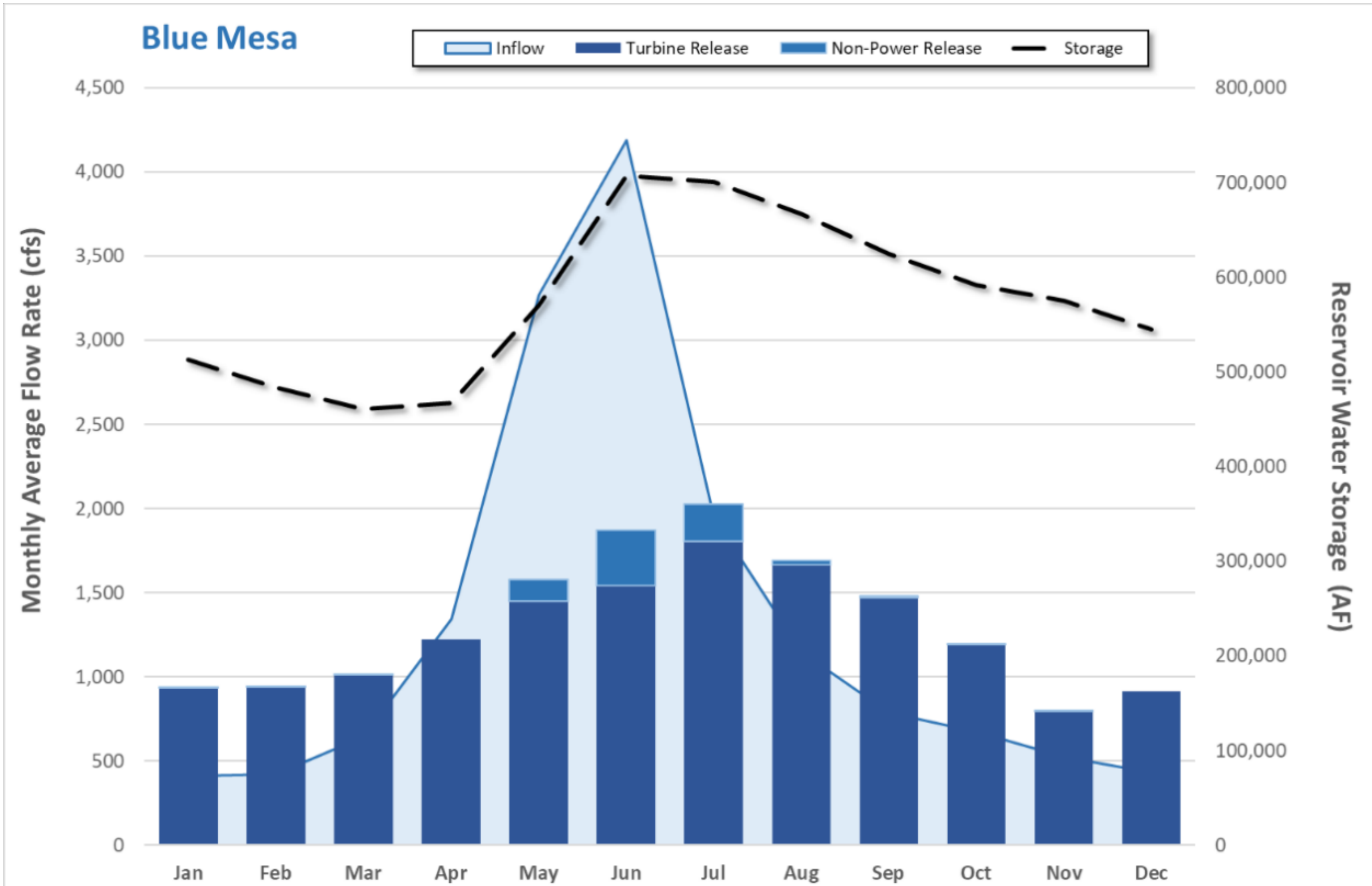


Figure 6-4 Average Monthly Pattern of Inflows, Turbine Releases, Non-power Releases, and Reservoir Storage Levels at BM

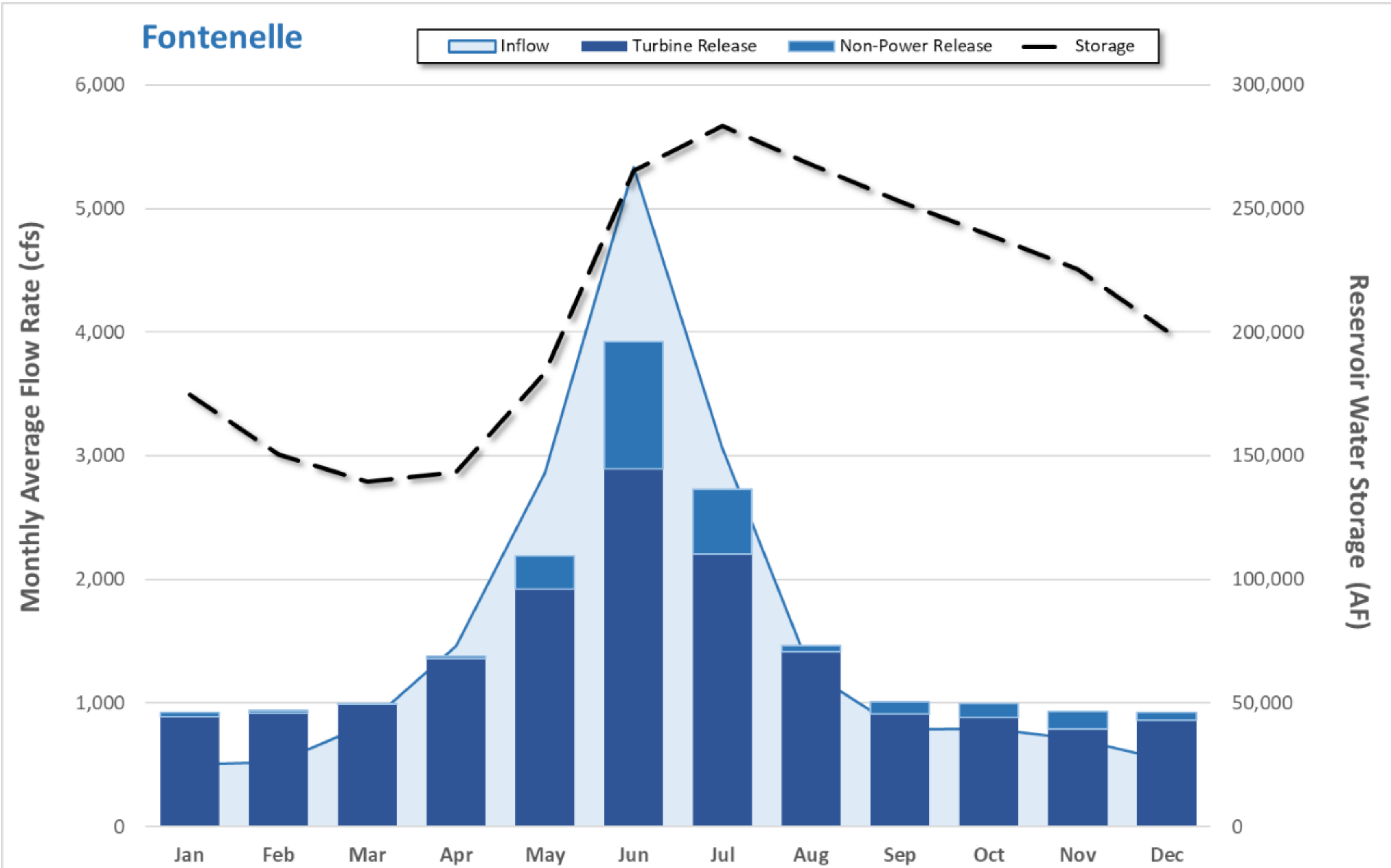


Figure 6-5 Average Monthly Pattern of Inflows, Turbine Releases, Non-power Releases, and Reservoir Storage Levels at FN

This page left intentionally blank.

7.0 Environmental Operating Criteria and Monthly Water Release Volumes

The shifting of reservoir monthly inflow volumes for release during a later time may be dampened or eliminated by environmental operating criteria. The "natural hydrograph" operating criteria may also lessen the benefits of reservoir storage on hydropower economics, which typically require water releases during the springtime when marginal energy values are lower than during the peak summer months. Other types of environmental operating criteria that impact hydropower value are requirements for special releases that are triggered by either hydrological events in the basin or releases that are needed to conduct environmental experiments, such as those described in Section 2.5.

These special releases may either increase or decrease the value of a hydropower plant. In some cases, an experimental/special release may yield a short economic benefit relative to the without-experiment condition while the experiment is being conducted. However, it may ultimately result in an overall decrease in value. For example, a very high constant water release that is sustained over several days to create downstream flooding yields relatively high economic value during the experiment. After the experiment, however, it results in lower water-to-power conversion efficiencies due to a lower reservoir elevation. In addition, water release volumes, either before or after the experiment, are reduced because water must be allocated from other periods to support high releases during the simulated/controlled flood.

Figure 7-1 shows estimates of annual environmental compliance costs for the Flaming Gorge (FG) Reservoir, which straddles the Wyoming–Utah border on the Green River. These costs are disaggregated into those associated with the monthly reallocation of water volumes relative to without-criteria volumes and those that are due to downstream Jensen Gauge flow restrictions, which impact daily and hourly generation/water release rates.

Note that costs and benefits (i.e., negative costs) associated with monthly water release volumes tend to be much larger than costs associated with gauge flow constraints. Whereas gauge constraints always incur an economic cost, the reallocation of monthly water release volume sometime yield an economic benefit. As shown on the left side of Figure 7-2, economic benefits occur when water is shifted (blue bars) from months that have low prices/marginal cost (e.g., September) to ones with higher values (e.g., May). On the other hand, environmental operating criteria incur a cost when water is shifted from high-energy-value months to months that have a lower value, as shown on the right side of Figure 7-2.

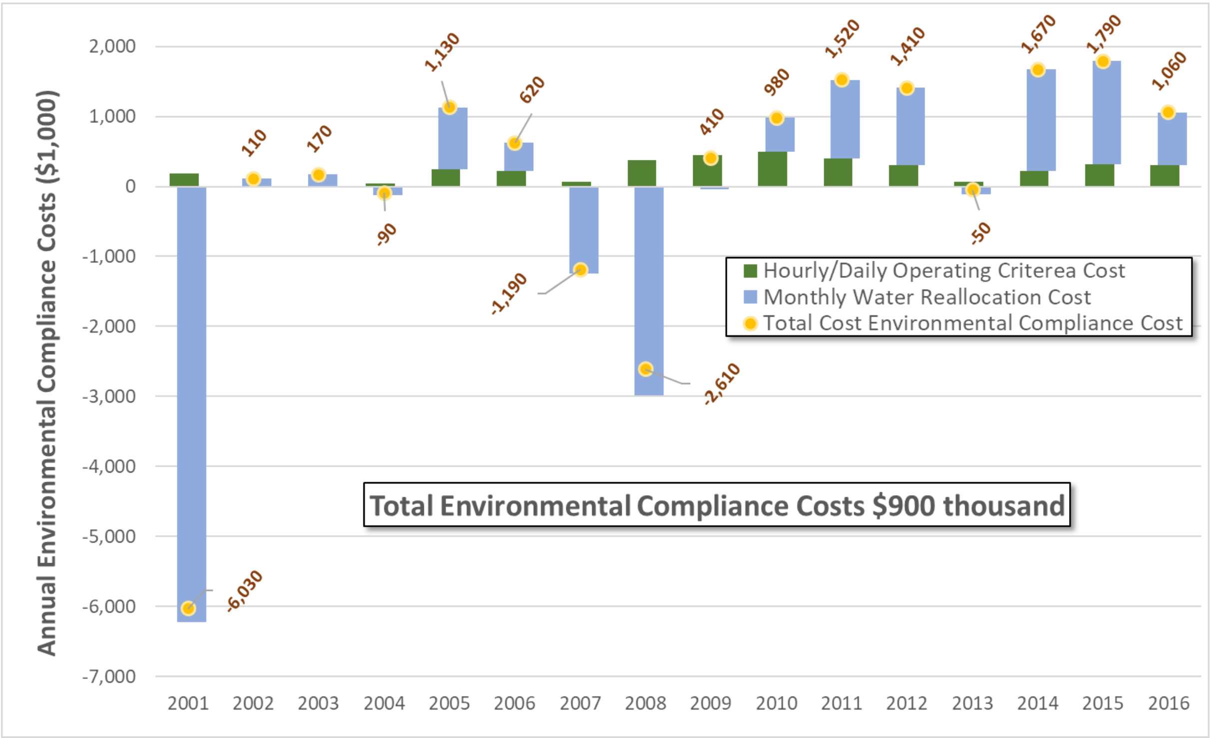


Figure 7-1 Annual Compliance Costs for Flaming Gorge Environmental Operating Criteria

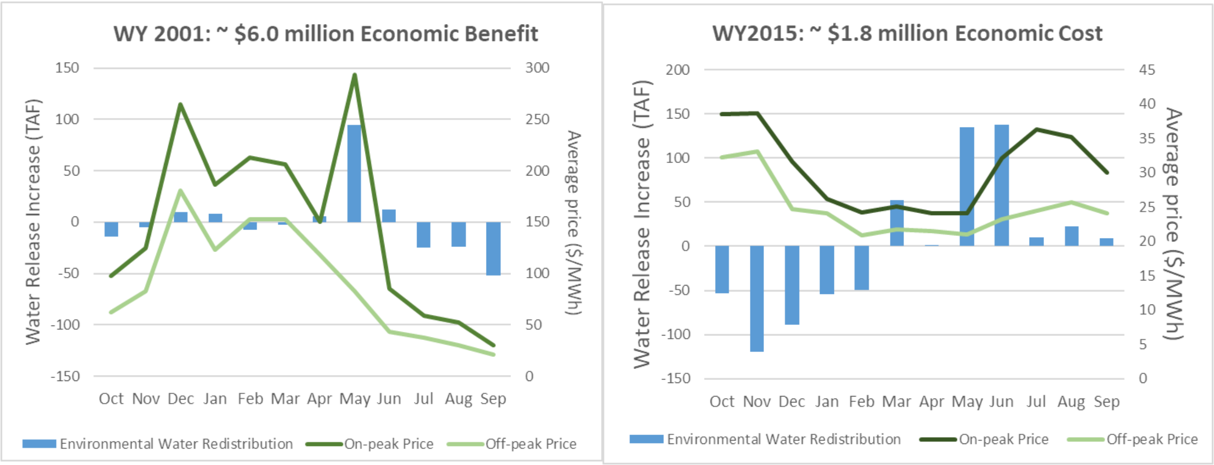


Figure 7-2 Monthly Compliance Costs for Flaming Gorge Environmental Operating Criteria during a Water Year that Yielded an Economic Benefit (left) and a Relatively Expensive Year (right)

8.0 Day-Ahead Scheduling and Real-Time Hydropower Capability Uses

Sections 2.3 through 2.7 discussed longer-term hydropower energy values from both multiyear (i.e., firm capacity credits) and seasonal/monthly perspectives (e.g., water storage/power production). This section expands upon earlier discussions to include shorter-term hydropower energy production values. It also provides details about several other uses of hydropower operational potential output beyond energy production. The day-ahead scheduling and real-time uses of hydropower capability are displayed in Figure 8-1.

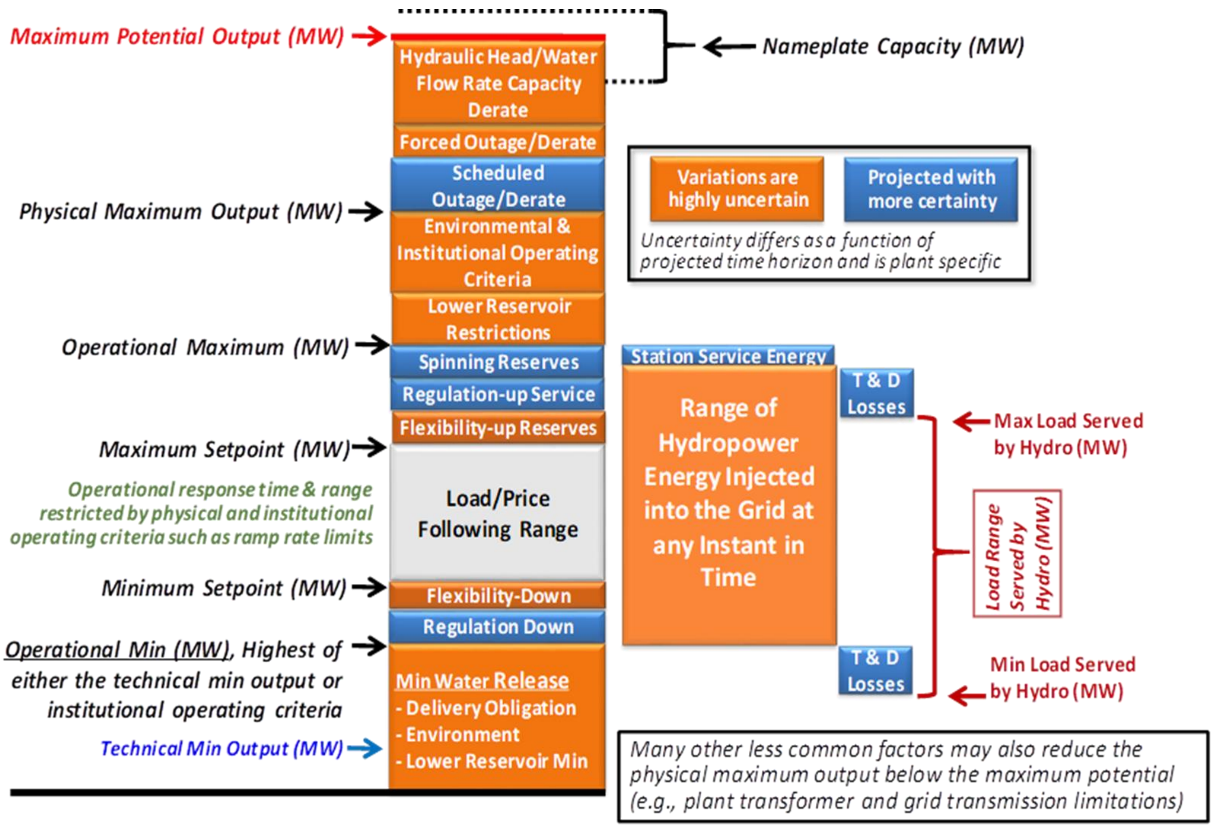


Figure 8-1 Hydropower Plant Uses and Limitations

Figure 8-1 also shows that the operational potential output of the hydropower plant cannot always be realized because of equipment outages, environmental operating criteria, forebay and afterbay limitations, constraints at a downstream reservoir(s), and/or downstream water delivery obligations. The “Hydraulic Head” block in Figure 8-1 illustrates the reduction of a plant capability because of either a low hydraulic head or limits on turbine water inflow rates.

ROR production capabilities are highly dependent on the stream inflow rate, while the physical maximum output for a storage/peaking hydropower plant is primarily a function of hydraulic head. Due to hydrological variability and equipment issues, the physical maximum output of a hydropower plant is often less than both its rated nameplate capacity and its maximum potential output. For instance, the maximum output of a hydropower plant increases with its hydraulic head, which depends on numerous factors, such as water inflows and outflows.

When a hydropower plant has flexible operations and is dispatchable, the operational maximum is used for (1) energy production to serve grid loads and for station service, (2) flexibility reserves to support grid VERs integration, (3) regulation up, (4) both spinning and non-spinning reserves, and (5) load/energy price load following and ramping. All blocks that represent operational flexibility vary widely in size among hydropower plants and over time.

The size of each block in Figure 8-1 is for illustrative purposes only. Actual block sizes are hydropower-plant-specific and change over time. For example, some plants such as pure ROR have a zero-block size for several components including regulation services, flexibility reserves, and load/price following because a ROR hydropower plant has very little, if any, operational flexibility. On the other hand, a ROR hydropower plant may at times have a very large block for the "Hydraulic Head/Water Flow Rate Capacity Derate" component. This block is relatively large when river channel flows are slow; however, at other times, when conditions are ideal, the block size is zero.

Block sizes for components that represent the use of the operable maximum capability above the minimum operation point are highly dependent on decisions made by the entities that schedule and operates the hydropower plant. These decisions are complex because the optimal capacity allocation needs to consider not only a timeseries of marginal values for each component, but also interactions with other hydropower resources including cascaded systems and overall grid response/reactions to these allocations. In a competitive market framework, values are also dependent on and/or influenced by collective decisions made by each of the independent entities that act autonomously within the constraints of the market(s) and system(s) in which it operates.

9.0 Hydropower Ancillary Service Value

9.1 Regulation Service

One of the ancillary service hydropower resources can provide is regulation. This capability is carved out so that a hydropower plant can react to rapid changes in system load, system generation deviations from schedules, and resource imbalances. Figure 9-1 shows power output from a hypothetical hydropower plant that provides both regulation-up (increase in output above the set point) and regulation-down services (decrease in output below the set point). Unit-level power output deviates from setpoint operations in response to AGC signals that are updated every 4 seconds. In order for a generating unit to respond to these signals, it must be already operating and synchronized with the grid.

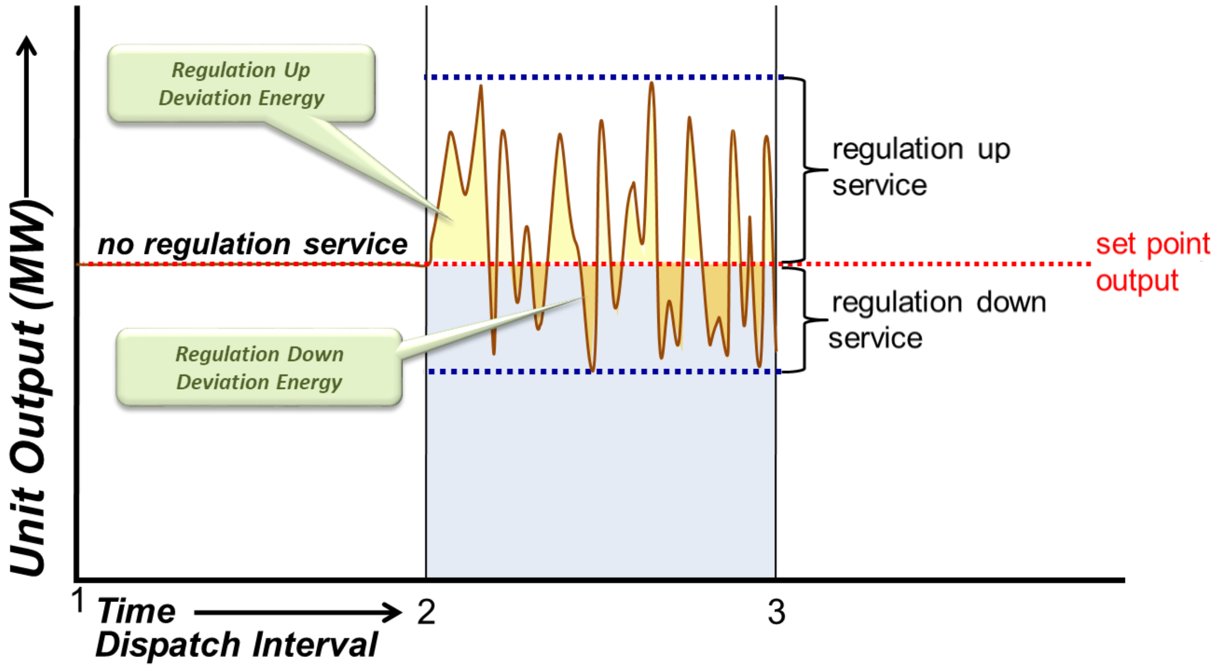


Figure 9-1 Regulation-Up and Regulation-Down Services

Figure 8-1 shows that generation capability must be reserved to provide regulation-up services. To accommodate increased output for regulation-up service, setpoint operations must back down from the operational maximum during the entire dispatch interval. The hydropower plant, therefore, cannot sell energy on the market at the operational maximum when prices are at a peak. This lower setpoint production level creates an opportunity cost (i.e., lower energy sales) associated to regulation-up services. Note that changes in power conversion efficiency between the operational maximum and the setpoint operation make the calculation of this opportunity cost complicated.

Figure 8-1 also shows that, to provide regulation-down services, the setpoint generation levels must be higher than the minimum operating point in order to accommodate decreases in output such as those in Figure 9-1. During periods of low price, regulation down has an opportunity cost because the additional water releases are used to support a setpoint power production level that is above the operational minimum. That is, to accommodate regulation-down service, the higher setpoint uses more scarce water resources that could have potentially been “stored” in the reservoir for power production during a time of peak prices/value.

There are two main kinds of environmental operating criteria: those associated with real-time restrictions, and those associated with restrictions on average values over a specified time interval. For example, the maximum flow rate constraint may be specified as an average flow rate over each 1-hour time interval. When operating at the setpoint at the maximum flow rate, hourly averaging allows a powerplant to provide regulation services such that regulation-up (+) and regulation-down (–) movements integrate to zero or less. This would allow instantaneous regulation-up movements into the "Environmental" block shown in Figure 8-1 and regulation-down movements below the environmental minimum. On the other hand, if criteria are based on instantaneous release rates, setpoint release/generation would need to be reduced by the regulation-up service capacity to ensure that instantaneous releases do not violate maximum flow criteria.

Regulation deviations over the length of a dispatch interval vary over time and are dependent on the characteristics and dynamics of the BA that a hydropower plant operates. A general rule of thumb is that the additional amount of energy generated by a hydropower plant when regulating in the up direction is equal to approximately 15% of the capacity reserved for regulation up multiplied by the duration of the dispatch interval. Similarly, less energy is injected into the grid when the power plant is providing regulation-down service. In the CAISO, energy-up deviations are paid the real-time energy price, slightly offsetting the opportunity costs associated with operating at a lower setpoint.

Power-plant entities are required to pay real-time energy prices associated with down-deviations that are often highly volatile, resulting in uncertainty/risks for the entity that is providing the service. Figure 9-2 shows that Palo Verde real-time market price spikes, both near and substantially above $1,000/MWh, occurred during several 5-minute time intervals. The highest price during the week of June 15 through June 21 was $1,348.70/MWh on the evening of Sunday, June 19. These price spikes are difficult to predict in advance based on other market price signals, such as those in the day-ahead and hourly market, which tend to be relatively stable.

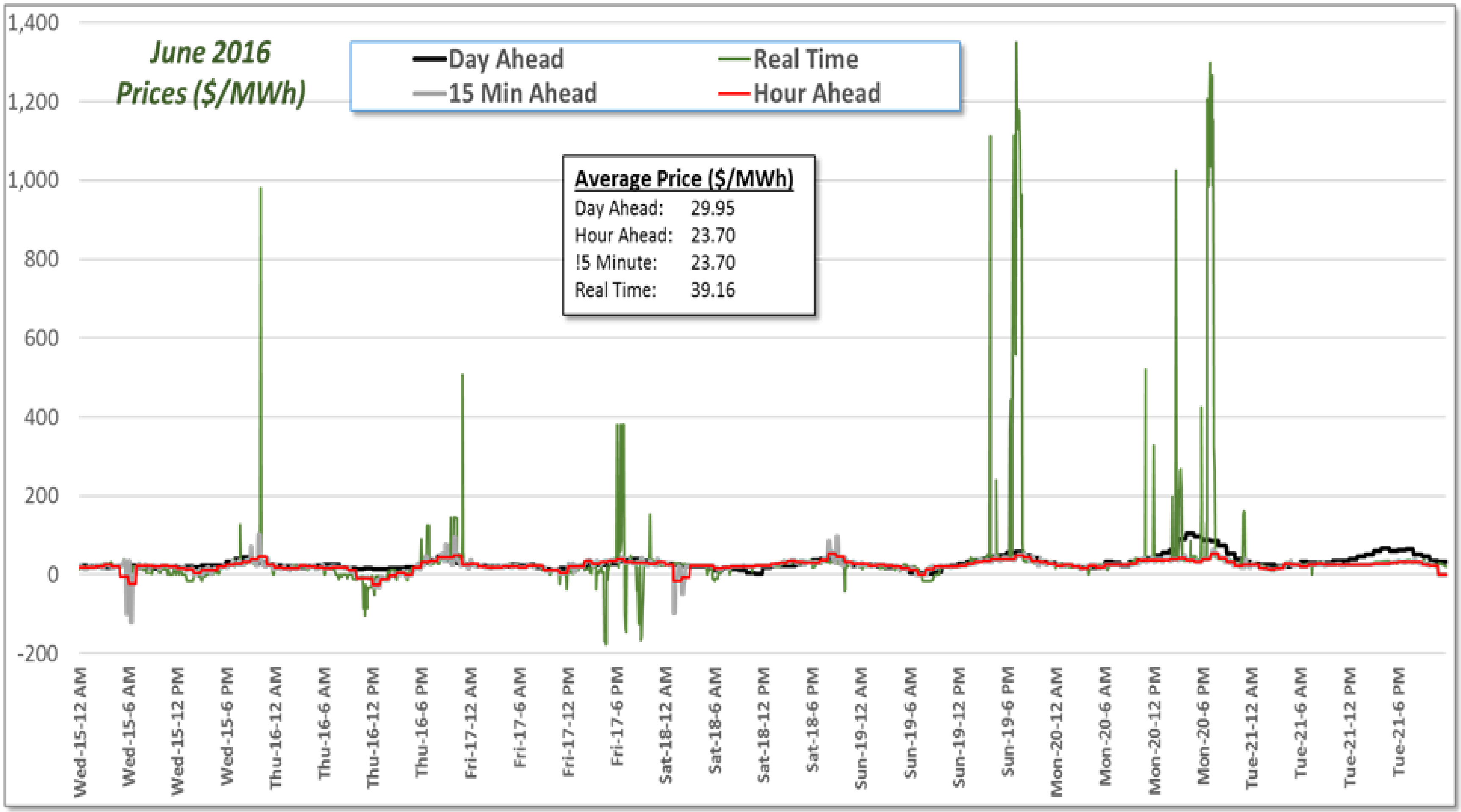


Figure 9-2 Day-ahead, Hour-ahead, 15-minute, and Real-time LMPs ($/MWh) at Palo Verde, June 15–22, 2016

Locational marginal prices (LMPs) sometimes exceed the bid cap of $1,000/MWh because at certain locations the price can be substantially higher than the highest accepted energy bid. This occurs when congestion charges and/or transmission loss components of the LMP equation are positive. Although real-time market prices are much more volatile than the day-ahead, hour-ahead, and 15-minute markets, the average real-time market prices over long periods (e.g., a month or more) for all three markets tend to be very similar.

On average, when providing identical levels of regulation-up and regulation-down services during the same dispatch interval, the regulation-up energy deviation is roughly equal to the regulation-down energy deviation. Water release reductions associated with regulation-down movements, however, may differ from water release increases that are used to serve regulation up. The water release difference stems from change in power conversion efficiencies between the setpoint and up- and down-regulation points (Figure 9-3). For example, when the setpoint generation is below the maximum efficiency point, the conversion efficiency could potentially increase when output deviation is in the up direction but decrease when deviations are below the setpoint.

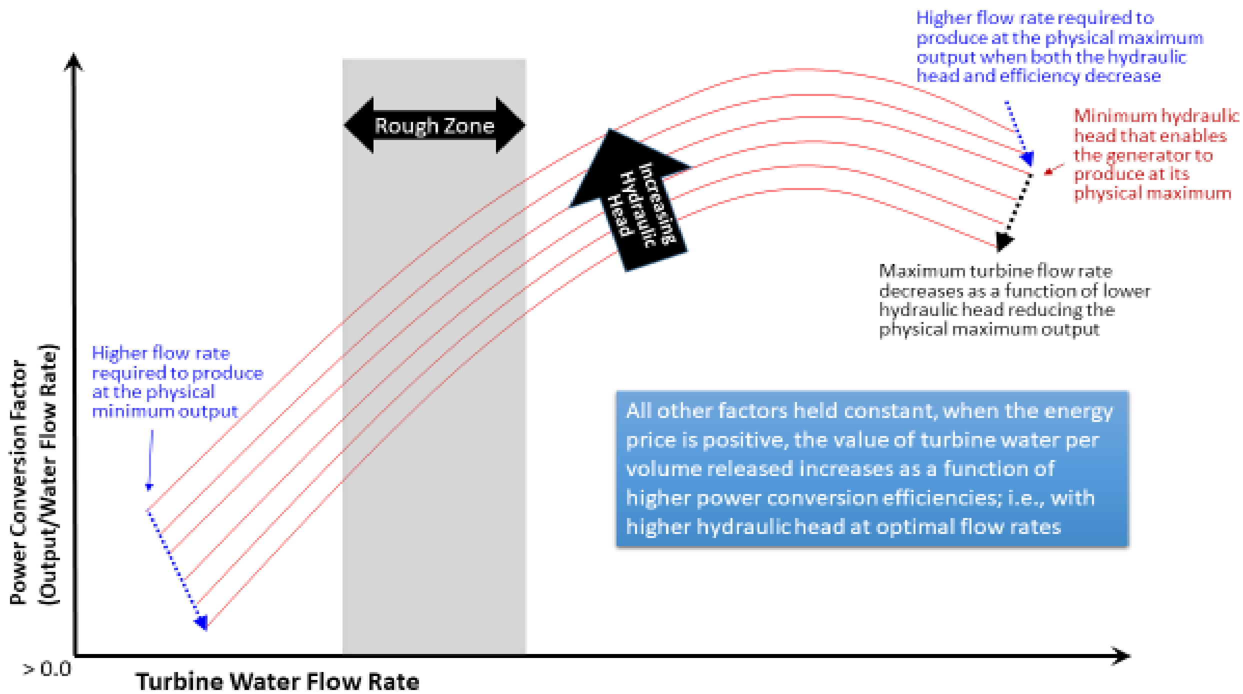


Figure 9-3 Hydropower Conversion Efficiency as a Function of Hydraulic Head and Turbine Water Flow Rate

Note that in Figure 9-1 regulation-up service provision is greater than regulation-down service. In some regional transmission organizations' (RTOs') and independent system operators' (ISOs') markets, such as the CAISO, asymmetrical regulation operations are common because regulations up and down are sold as two separate products. On the other hand, other markets and BA operating rules only have a single regulation product, in which case the regulation-up capacity must equal the regulation-down capacity.

Hydropower plant regulation service levels may be restricted by a generator rough zone in which flows and/or generation levels within the zone produce mechanical vibrations that may damage a turbine. Notice that in Figure 9-4 the actual unit hourly generation levels (red and blue points) for a WI plant avoid this zone. The rough zone limits the maximum regulation-up service provided to the grid when the set-point is below this zone and limits regulation-down service for set-points above the zone.

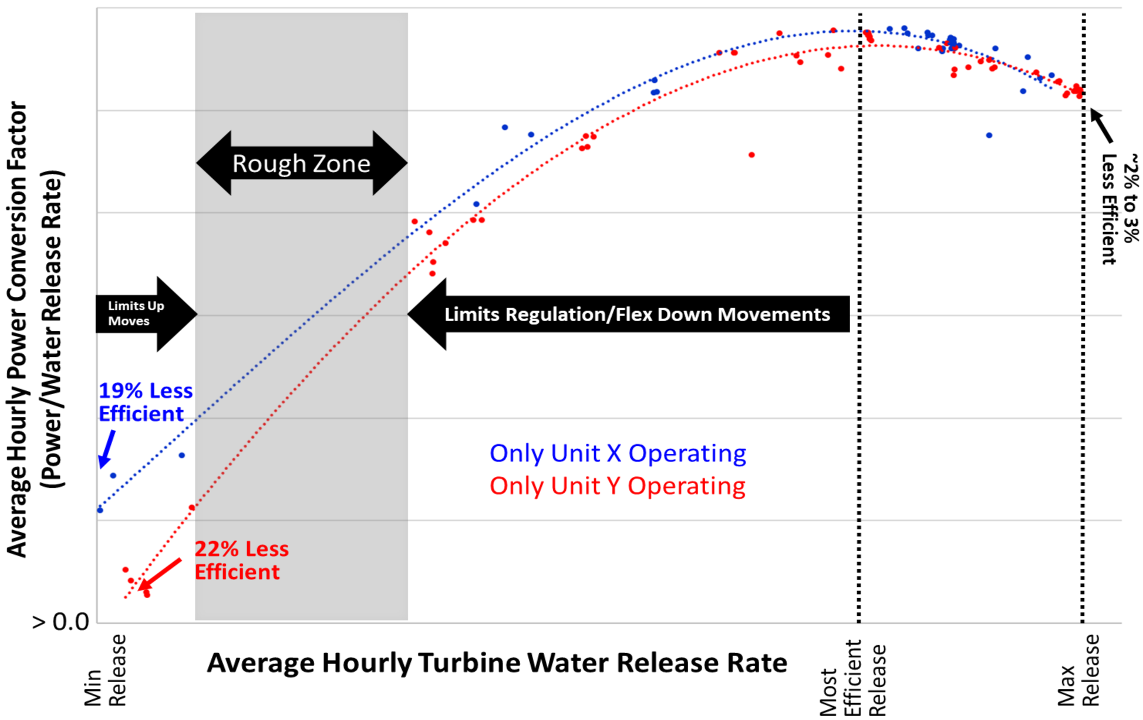


Figure 9-4 Power Conversion Factor Is Affected by Generation Movements that Support Regulation Services

9.2 Spinning Reserves

Hydropower plant operating capability used for spinning and non-spinning (contingency) reserves is needed to support grid reliability. To provide the spinning reserve service, a power plant should be synchronized with the grid. However, it does not necessarily need to inject setpoint energy to the grid. In addition, spinning and non-spinning ancillary services typically do not have energy production deviations.

Spinning reserve energy deviations from setpoint operations only occur in the "up" direction and are infrequent responses to grid events such as the loss of a generator (i.e., forced outage). In WECC, the spinning reserve capacity must be fully deployed within 10 minutes of notification. Once deployed, the plant must be able to provide energy up to its spinning reserve obligation for the first 105 minutes (15-minute disturbance recovery period, plus a 90-minute contingency reserve restoration period) following the event that activated contingency reserves. For peaking hydropower plants, there must be an adequate volume of water available in the upper reservoir for 105 minutes of power output at full capacity in addition to water release needed to support setpoint generation. Likewise, in situations where there is a lower reservoir, there must be adequate water storage space available to accommodate higher-than-scheduled inflows.

Even when not deployed, contingency reserves have implications for water releases and therefore system economics. Providing reserves effectively reduces the maximum operating setpoint of a turbine. Similar to regulation-up services, it also affects the hydropower plant conversion efficiency. Figure 9-5 shows a one-day winter operating profile for the Green Peter Hydropower Plant that has two units with equal nameplate capacity. Note that by operating below the plant maximum output, its generation level is probably near its optimal efficiency point, which allows the units to produce more power per volume of water released than at other operating points (e.g., at full capacity). In addition to the economic value of energy, the plant operation also yields economic value by providing spinning reserves to the system; that is, if the Green Peter Plant did not provide this service, it would need to be served by another resource that perhaps would have incurred higher grid costs.

Figure 9-6 illustrates the Green Peter Hydropower Plant operation during a summer day. In this example, water resources are scarcer relative to the winter. Therefore, only one unit produces power during the afternoon/evening peak load period. To conserve water, generation during the rest of the day is zero. Note that in this summertime example, the unit provides spinning reserves during all hours of the day, including times that have zero generation levels. Presumably, during these zero-generation hours, the units are idling in a synchronous condenser mode.

Environmental operating criteria, such as the ones at GCD, may grant spinning reserve exceptions. When there is a grid emergency, these exceptions allow the power plant output to deploy the reserves, exceeding both the operational maximum and the normal maximum environmental water release rate limit. The maximum setpoint, therefore, is subject to the less constraining maximum physical output and the amount of contingency reserves that are provided by the units. Without exception criteria, the setpoint would be lower, which would in turn reduce the economic value of the GCD operating capacity.

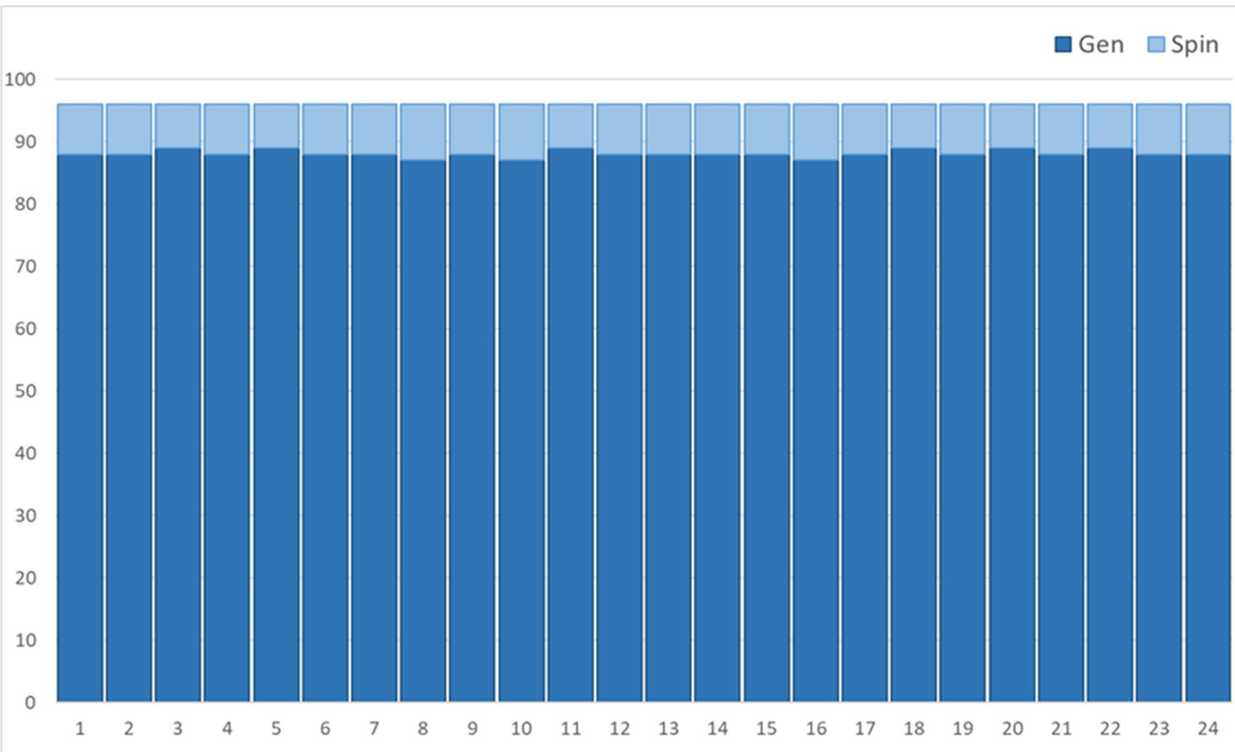


Figure 9-5 Hourly Generation (MWh) and Spinning Reserves (MW with Hourly Durations) Profile for Green Peter Plant, February 26, 2014

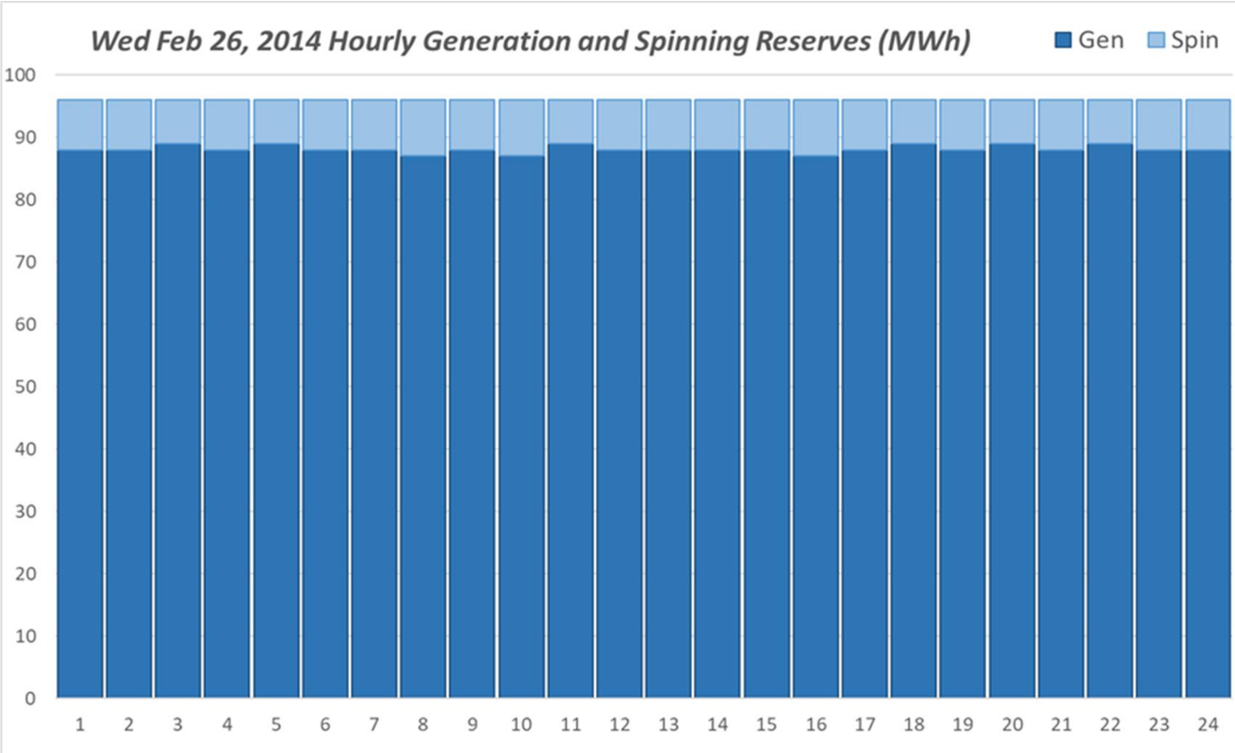


Figure 9-6 Hourly Generation (MWh) and Spinning Reserve (MW with Hourly Durations) Profile for Green Peter Plant, August 23, 2017

9.3 Ancillary Service Costs

Ancillary services required for power system supply/demand balancing, reliability, and stability incur economic costs. Because flexible hydropower plants can very quickly react to changes in the state of the grid at a relatively low cost, hydropower is often used to provide these services. As illustrated in Figure 8-1 an entity that provides ancillary services needs to carve some of the hydropower plant's maximum operating capability to support these services. Minimum generation level may also need to be increased in order for operations to remain within physical and institutional limits. This reserved capacity cannot be utilized to produce energy to serve peak loads when system/grid marginal production costs are expensive. On the other hand, a power plant needs to be operating at relatively high level during low demand/price periods. This narrowing of the load-following range increases the total economic cost of the system dispatch.

In structured power markets, those entities that provide ancillary services are paid separately through market mechanisms—typically at the ancillary market clearing price. In BAs that do not participate in formalized ancillary services markets, these services are typically coordinated by the BA operator. This section describes a case study that computed ancillary costs in a BA without a formal market. Ultimately these costs are passed down to entities that reside in the BA.

In an analysis of the financial and economic implications of a proposed Rocky Mountain Transmission Group joint-tariff market, WAPA and Argonne estimated that costs associated with the WAPA Loveland Area Projects (LAP) Office carrying operating and contingency reserves at LAP hydropower resources in the WAPA Colorado-Missouri Region (WACM) BAA.[41] To estimate the LAP costs, Argonne conducted a comparative analysis in which they computed energy benefits/revenues for two different cases: one with ancillary services (the status quo case) and another without ancillary services (the counterfactual case). In the counterfactual case, the capacity carved out to provide services was freed up for dispatch as energy sales.

In support of the study, LAP schedulers created two hourly generation profiles under identical average hydropower conditions. The first schedule assumed that the Yellowtail Powerplant would provide all BAA ancillary services. In the second schedule, no ancillary services were required at the Yellowtail Powerplant. The assumption that all ancillary services would be provided by Yellowtail under the status quo case is a simplification for the sake of modeling. The error associated with this simplification was judged to be small because, historically, most of the time all ancillary services have been carried at Yellowtail.

Because the year simulated was 2024, we assumed that Yellowtail rewinds/upgrades would be completed by that year, increasing the powerplant capacity by about 10 MW. These plant improvements were assumed to occur under both with and without ancillary services cases. The difference in the computed revenues under the two generation schedules roughly approximates LAP financial gains associated with the freed-up ancillary service capacity.

Schedules created by LAP experts not only included generation but also hourly water release schedules. In the status quo case, special attention was paid to not only reserving sufficient capacity for serving ancillary services, but also ensuring that both reservoir and afterbay operational criteria would not be violated if spinning reserves needed to be deployed. Water releases were identical under both cases; however, generation levels differed because scheduling points affected the operational efficiency of power-plant operations. In addition, water was sometimes spilled at Yellowtail in order to provide ancillary services.

Based on current day-ahead market scheduling practices, hourly Yellowtail release/generation profiles were created for a typical week each month under both cases for a total of 24 weekly profiles. Profiles were produced using current scheduling spreadsheet tools. Given these generation profiles, Argonne staff calculated financial savings for LAP using Brattle LMP projections at Yellowtail under the current trends future. Weekly financial results were scaled to monthly profiles considering the number of day types (Saturday, Sunday, Monday, etc.) that occur in the year 2024. Holidays, however, were not considered in either the creation of weekly Yellowtail schedules or financial calculations because doing so would have resulted in inconsistent water release quantities between the two cases.

Monthly and total cost results are shown in Figure 9-7. Note that about 63% of the annual savings is projected to occur in June. During this month, water releases are at a high point and the power plant is utilized either fully or nearly fully much of the time. Using all the available water to produce energy leaves little available capacity to provide ancillary services. Generation schedules must therefore be dialed back by releasing some water through the plant's bypass tubes in order to have adequate generating capacity to provide regulation-up services and, if needed, to deploy spinning reserves. The June savings are therefore primarily due the elimination of non-power water releases under the counterfactual case (see Figure 9-8). Note that in the lower table about 41.1 GWh more energy is produced under the counterfactual case.

[41] WAPA, 2017, *Mountain West Joint Tariff and Regional Transmission Organization Market Study: LAP and CRSP Financial Analyses*, September 5. https://www.wapa.gov/About/keytopics/Documents/LAP-CRSP_Production-Cost-Study.pdf.

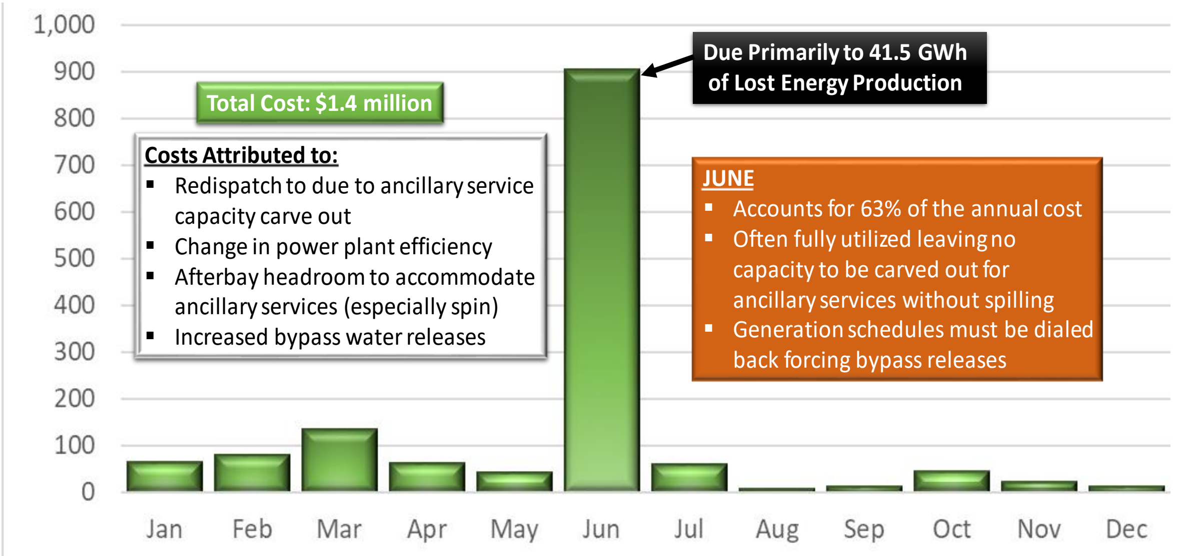


Figure 9-7 Opportunity Costs ($1,000) for Yellowtail Hydropower Plant Ancillary Services

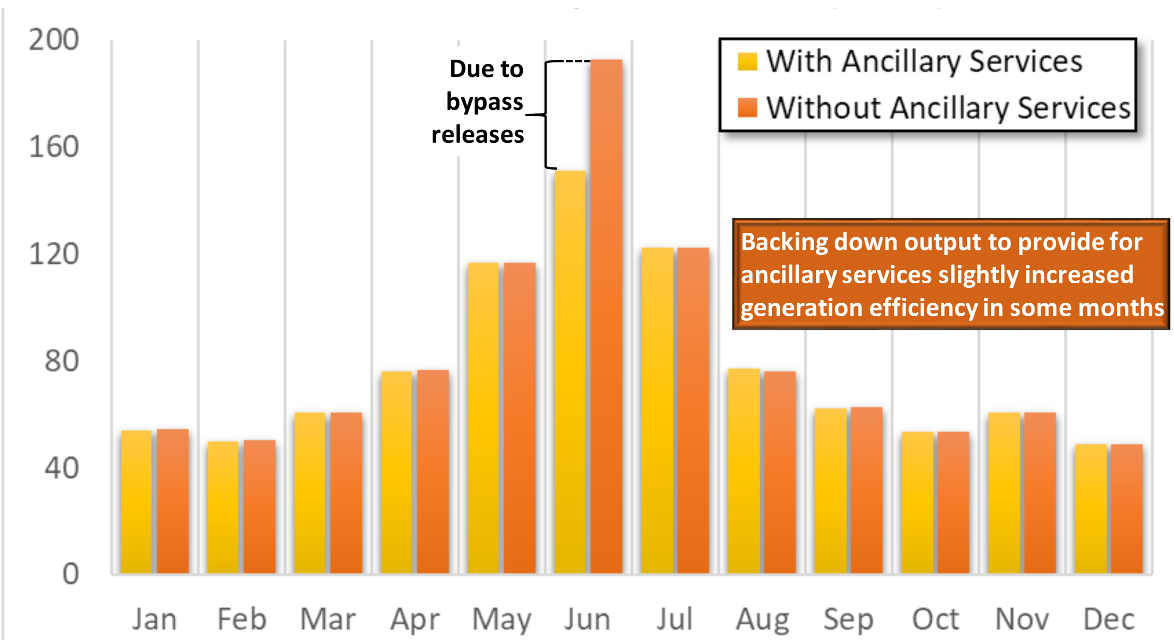


Figure 9-8 Yellowtail Hydropower Plant Monthly Generation (GWh), Status Quo and Counterfactual Cases

This page left intentionally blank.

10.0 Value of Hydropower Plants for VER Grid Integration

Hydropower plants play a key role in the integration of VERs into the power grid. Renewable energy sources such as wind turbines and solar panels are variable energy producers that are typically balanced in real-time grid operations by adjusting output from flexible supply resources. For example, peaking hydropower plants partially or fully balance grid load and supply by adjusting output levels opposite the movements of VER production. Hydropower plants that have both fast ramping abilities and a reservoir that can store water releases for sustained operations at maximum power output for several hours are very effective resources for providing ancillary services.

VER generation levels in the United States, including those located in the WI, have grown rapidly over the past decade. This growth is expected to continue in the future because utilities strive to comply with state Renewables Portfolio Standards (RPSs). For example, in California the RPS that was enacted in 2002 required that 20% of the state's energy demand would be served by renewable energy by 2010. The most recent California RPS, however, increased the target to 60% by the year 2030 and 100% by 2045.

The WI may be better suited to accommodate the integration of a higher VER penetration level and at a lower cost than other regions in the United States because many WI hydropower plants haves a high degree of operational flexibility. This allows hydropower operations to rapidly react to changes in VER production. As discussed earlier, the WI hydropower nameplate capacity accounts for about 54% of the national hydropower nameplate capacity and WI hydropower production represents over 60% of national hydropower production. Much of this capability has at least some operational flexibility (see Figure 2-1).

10.1 Wind Power

Growth in wind generation in the WI and the rest of the United States is shown in Figure 10-1. It shows that production in the WI is growing, but at a lower rate than in the rest of the country. The lower growth rate in the western United States may be because wind speeds in the WI are on average somewhat lower than wind speeds in the central United States (Figure 10-2) where wind capacity expansion has grown the fastest. However, there are areas within the WI where wind generation growth is expected to be significantly faster than the WI average.

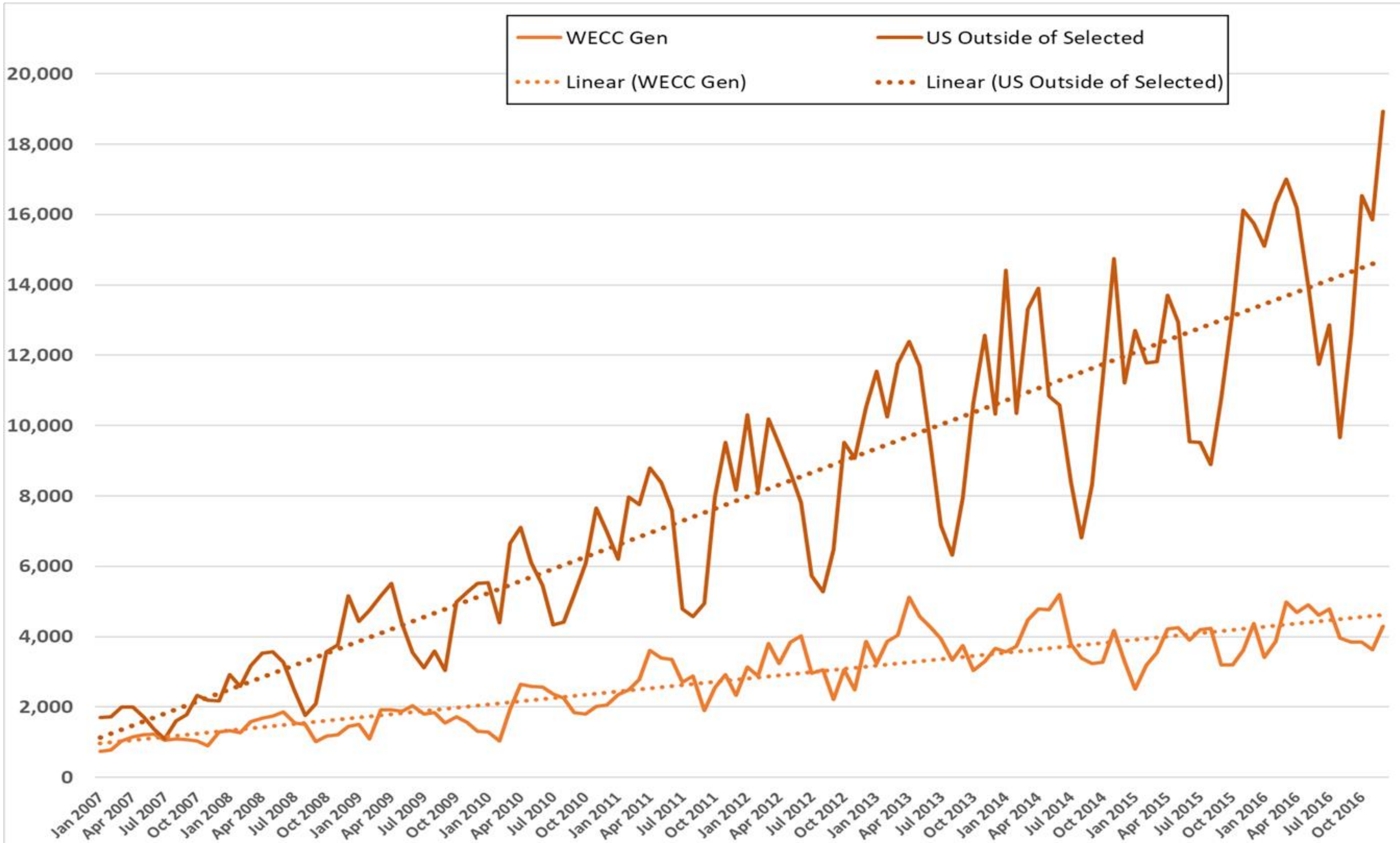


Figure 10-1 Monthly Generation (GWh) Profile of Wind Energy in the WI and the Rest of the United States

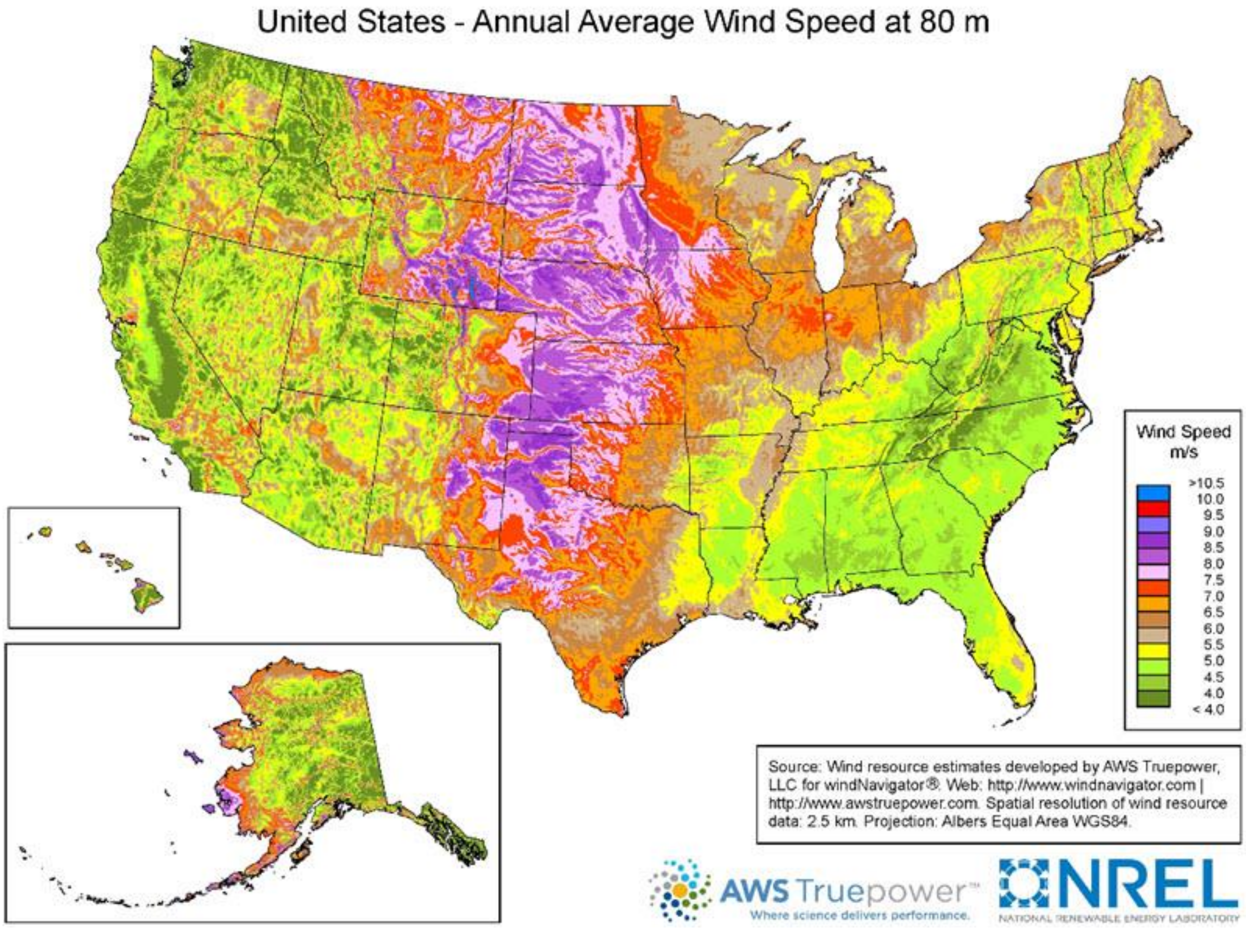


Figure 10-2 Average Annual Wind Speed at 80 m Height in the United States, 2009–2010

For example, in the WACM BAA, wind power generation has increased substantially over the past few years and additional wind resources are expected to be built in the future. The WAPA LAP Office operate this BA and both the LAP and CRSP Offices preform day-ahead and real-time generation scheduling for numerous Federal hydropower plants that are located within this footprint. The operation of the both the BA and Federal hydropower which have been affected by wind expansion and the operational impacts are expected to increase in the future.

As part of an EIM study that Argonne conducted for WAPA, Argonne analyzed projected VER penetration within the WACM BA.[42] It showed that VERs in the WACM footprint, as projected by the WECC Transmission Expansion Planning Policy Committee (TEPPC), will have large and rapid production changes over time. Figure 10-3 shows projected VER production from March 14 to 20, 2020, and the percentage of BAA hourly load served by wind (on the secondary y-axis). Note that hourly wind production ranges from zero to the maximum installed wind capacity and the percentage of load served by wind varies from zero to almost 40%. In addition, changes in wind production from one hour to the next (i.e., wind production hourly ramp) is expected to be at times very rapid, with up-ramps exceeding 450 MW/hr and down-ramps of over 300 MW/hr (red line in Figure 10-3).

[42] T.D. Veselka, L.A. Poch, and A. Botterud, 2012, *Review of the WECC EDT Phase 2 EIM Benefits Analysis and Results Report*, ANL/DIS-12-2, April. https://publications.anl.gov/anlpubs/2012/04/73032.pdf.

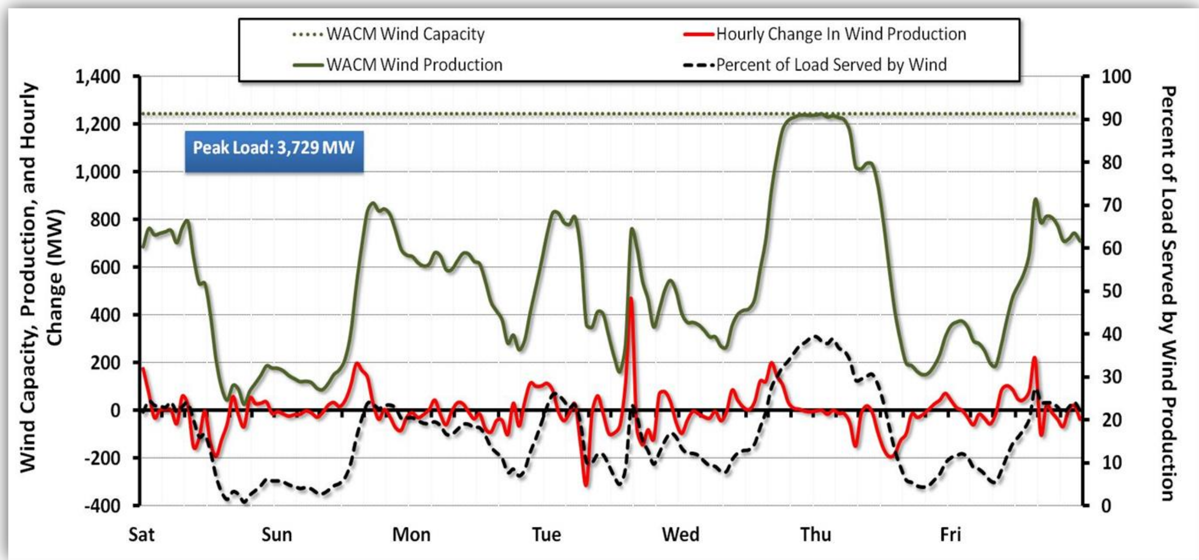


Figure 10-3 Projections of Wind Production for WACM BAA, March 14–20, 2020

Currently, federal hydropower plants provide regulation services to balance loads and resources within the WACM BAA. In the future, balancing VER penetration levels projected by TEPPC will become more challenging and may also require higher than current-day levels of both flexible and regulation reserve capacity to insure reliable BA operations. This increased need may potentially be served via WAPA Federal hydropower resources; that is, more BAA hydropower capacity may be required to provide a combination of regulation and flexibility reserves (flex-reg) to keep the system in balance. As VER penetration in the BAA increases, BA operators may also require regulation and flexibility service contributions from other supply resources, such as gas-fired turbines, that are located in the BAA.

10.2 Solar Power

Figure 10-4 shows that, in 2016, the WI interconnection had almost 3 times more solar production than as the rest of the nation. It also shows that the growth of solar production from 2012 through 2016 has been much faster in the WI than in the rest of the United States. This can in part be attributed to high solar irradiance in the southern half of the WI, as shown in Figure 10-5.

Unfortunately, this dry and sunny region of the country has few hydropower resources. For example, the Arizona Public Service (APS) footprint currently has several photovoltaic and two concentrating solar resources within its footprint. Figure 10-6 shows actual minute-by-minute solar output for a summer day.[43] The high volatility of real-time solar generation in this region raises the need for flexible sources. However, there are no hydropower resources within the Arizona Public Service BA (AZPS) footprint to either provide flexible reserves or resolve real-time energy imbalances (see “APS” data displayed in Figure 2-4). AZPS BA operators reserve capacity with AGC on operating units in order to respond to these rapid solar output changes by adjusting production levels from reserve capacity within the BAA.

[43] Arizona Public Service Company, 2014, “2014 Integrated Resource Plan,” APS, Arizona Department of Environmental Quality Stakeholder Meeting, April, http://www.oatioasis.com/AZPS/AZPSdocs/2014-04-01_Integrated_Resource_Plan.pdf

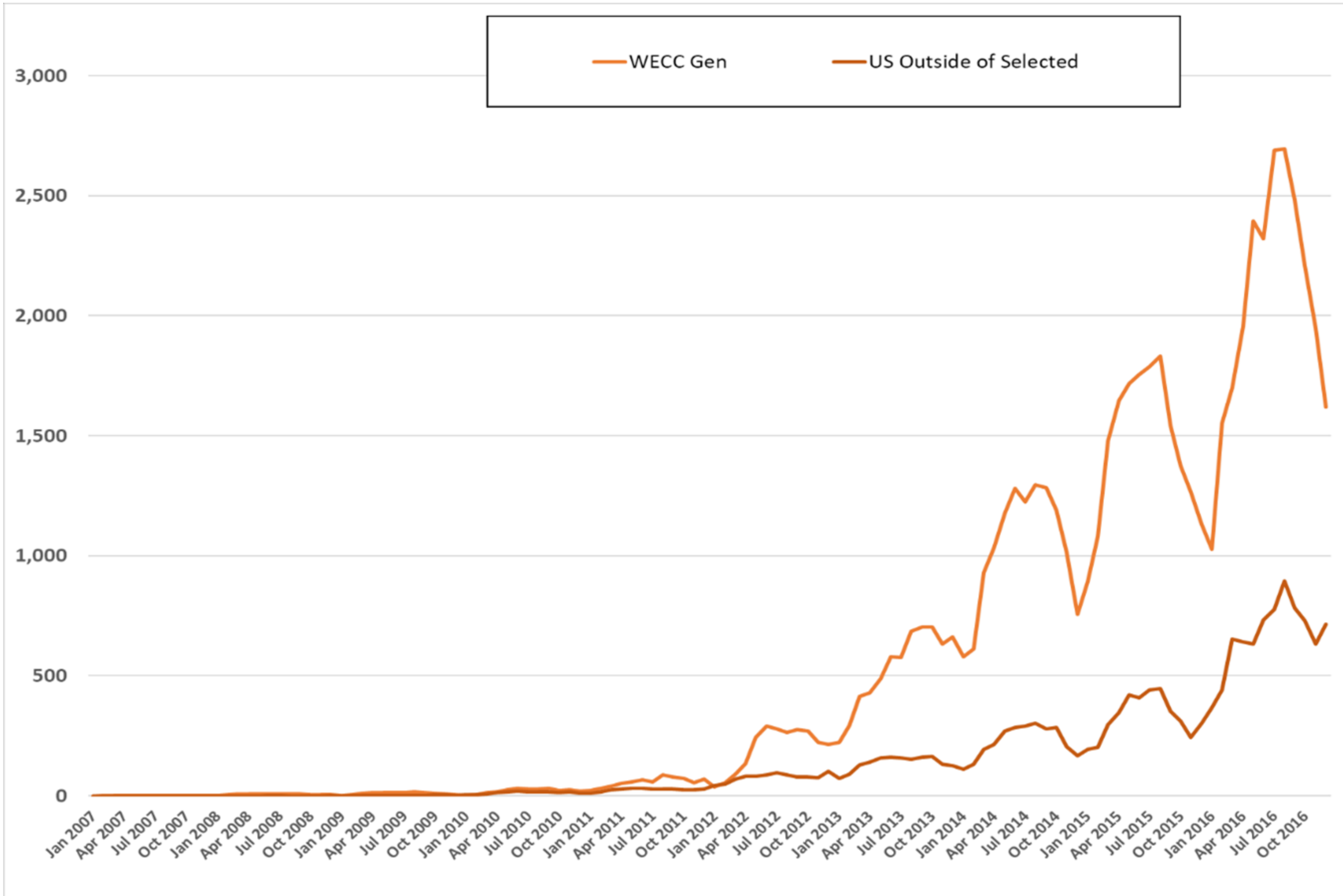


Figure 10-4 Monthly Generation (GWh) Profile of Solar Energy in the WI and the Rest of the United States

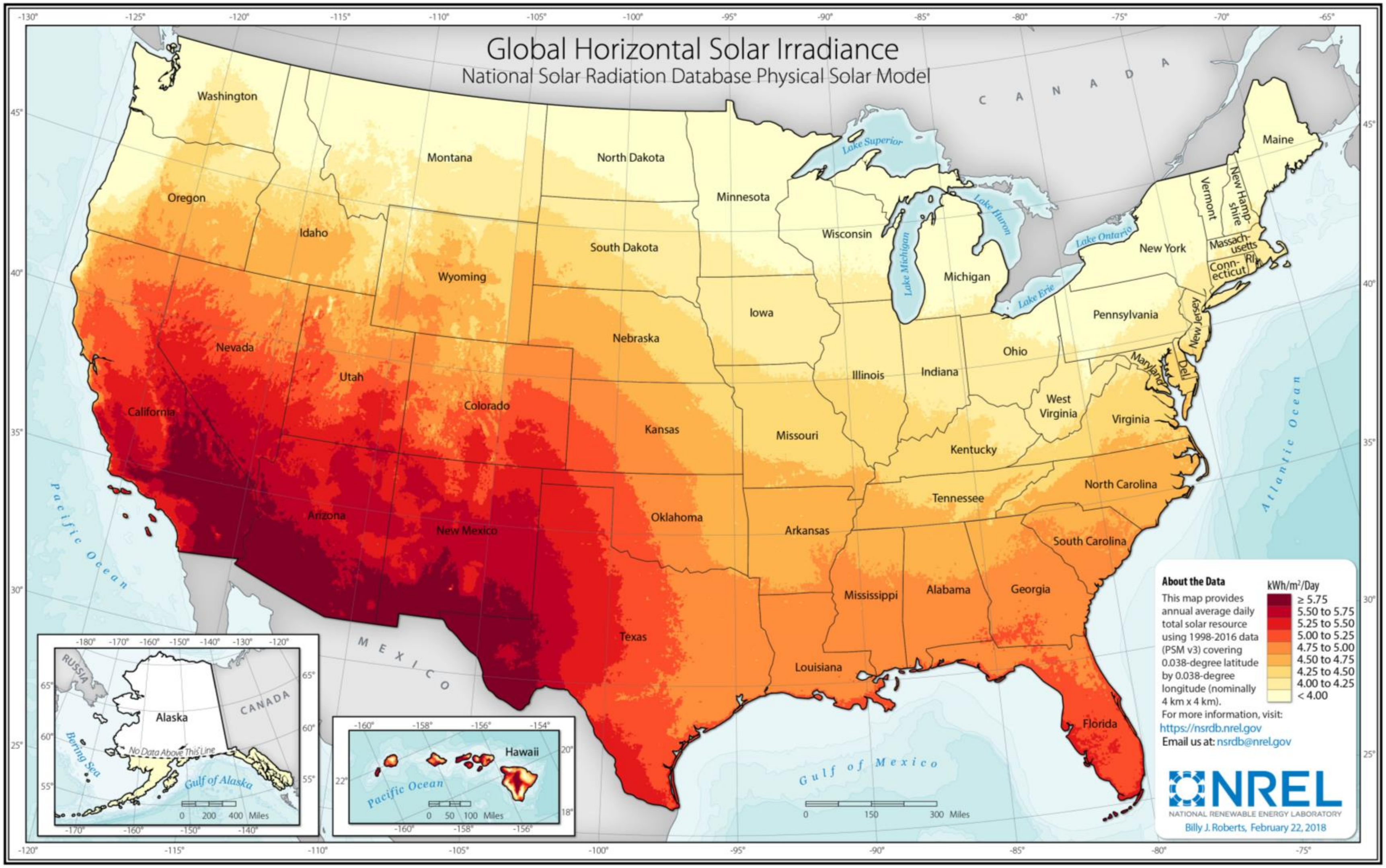


Figure 10-5 U.S. Global Horizontal Solar Irradiance

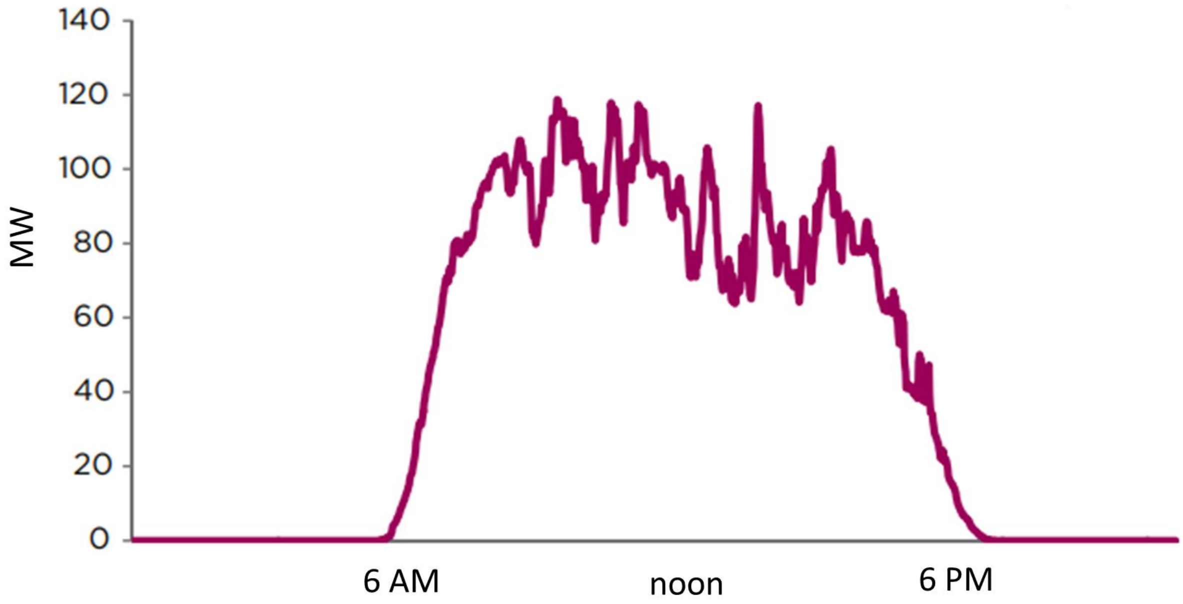


Figure 10-6 Actual Summer Day Output Produced by an APS Photovoltaic Resource

It is anticipated that the APS system will continue to evolve in the future with substantial VER capacity and energy production growth. Figure 10-7 is a graph of APS net load projections during off-peak months/seasons.[44] By 2029, system loads minus VER production under non-summertime conditions are projected be the lowest during the middle of the day and ramp-up very quickly throughout the early evening. Mainly due to solar production, the general shape of this profile is similar to the one projected for CAISO net BAA loads (i.e., loads less VER energy productions) in 2020.[45]

[44] Arizona Public Service Company, 2014, "2014 Integrated Resource Plan," APS, Arizona Department of Environmental Quality Stakeholder Meeting, April, http://www.oatioasis.com/AZPS/AZPSdocs/2014-04-01_Integrated_Resource_Plan.pdf

[45] The CAISO net load chart is often referred to as the "duck chart."

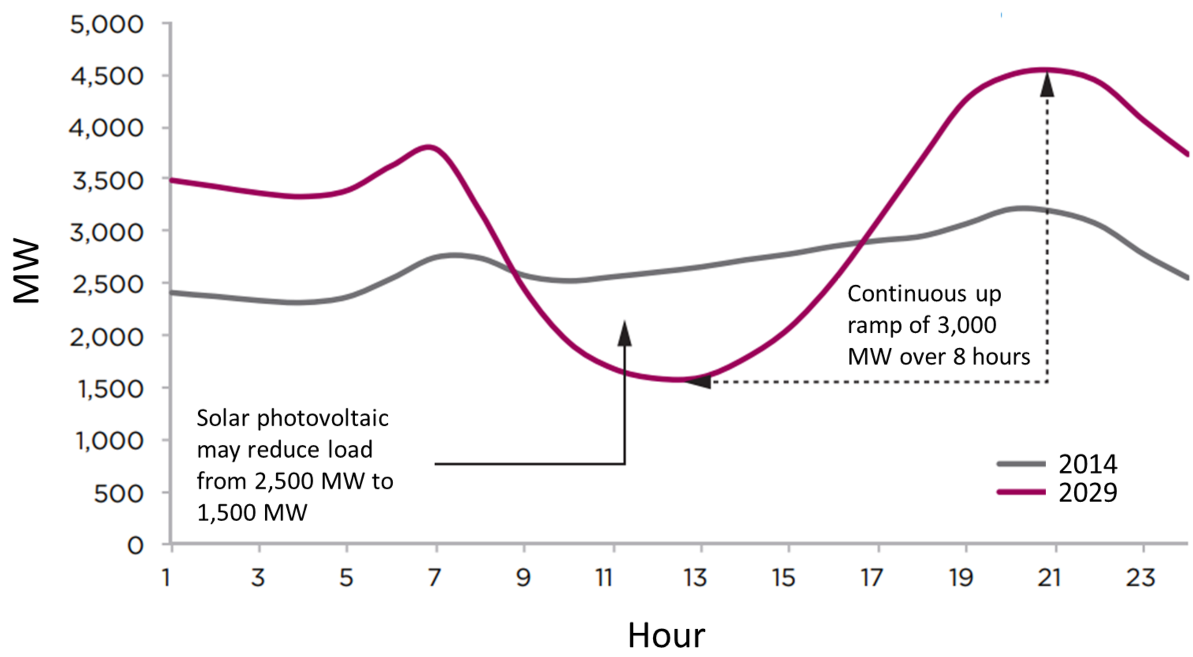


Figure 10-7 Projected Net Demand (load-VER production) during Non-summer Days

A major concern of the net load profile is its very low value during the middle of the day followed by a rapid increase during the afternoon and evening, which poses a unit commitment problem. BA operators must shut down units in the middle of the day to avoid over-generating (over-supply imbalance). On the other hand, it may not be possible to bring the units back online in time to meet the evening peak load, resulting in a potential under-supply imbalance.

In addition to the unit commitment problem, online units must have sufficient ramping capabilities to follow the morning generation decline and the rapid afternoon load increase. Units that have high minimum technical generation levels and take a long time to shut down and start up, such as generators that use steam as a primary mover, greatly exacerbate the problem. Therefore, according to the APS IRP, new thermal constructions will primarily consist of gas-fired units that can be turned both on and off within a short period of time and respond quickly to both changes in VER output and deal with net load forecast error.

Another potential technology solution to the duck curve problem is to build pumped storage hydropower plants (PSHs).[46] During the middle of the day, pumps would be turned on, thereby increasing load to fill part of the net load valley. Then, during the evening hours, the PSH plant would be in generation mode to reduce the net peak load (i.e., peak shaving). This would effectively reduce the amount of thermal-system ramping. In addition, when in generation mode, the PSH plant could potentially provide regulation and flexibility reserve services for the BA along with contingency reserves. Conventional PSHs would not be able to provide these types of ancillary services when in pump mode because conventional pumps can only operate in either full on or full off modes. However, adjustable-speed PSHs employing doubly fed induction machines would be able to adjust pumping loads, thereby enabling the PSH plant to also provide regulation and flexible reserve services in pump mode operations.

[46] H.O.R. Howlader, M. Furukakoi, H. Matayoshi, and T. Senjyu, 2017, "Duck curve problem solving strategies with thermal unit commitment by introducing pumped storage hydroelectricity & renewable energy," 2017 IEEE 12th International Conference on Power Electronics and Drive Systems (PEDS), Honolulu, HI, pp. 502–506. doi: 10.1109/PEDS.2017.8289132

10.3 Flexibility Reserves and Ramp Reserves for VER Integration

Flexible reserve capacity is deployed in response to grid VER power production forecast errors. As shown in Figure 8-1, there are flexible reserves in both the up and down directions, which enables a hydropower resource to respond to both lower-than-forecasted/scheduled VER production (flexibility up) and higher-than-forecasted VER production (flexibility down). Both narrow the load/price following range. The amount of capacity that is needed in each direction depends on several factors including, but not limited to, VER system-level capacity penetration rate, VER resource geographical locations, VER production diversity, transmission system constraints, VER forecast accuracy, and the risk tolerance of grid operators/regulators.

VER capacity reserve requirements are also dependent on the characteristics of the VER technologies that are in the grid, as illustrated in Figure 10-8 for a wind technology. The figure shows a generic power curve for a single wind turbine and the incremental power change resulting from a small change in wind speed (i.e., instantaneous slopes along the power output curve). Under very low wind conditions, a wind turbine does not produce power because there is not enough force to rotate the turbine blades. Power production begins at the cut-in wind speed and initially increases relatively slowly as a function of faster wind speeds. If the wind speed is projected to be in this relatively low range, then the corresponding scheduled power output is small. Note that when the wind speed is projected to be low, the average generation forecast error also tends to be relatively small because a small to moderate wind forecast error translates into a small difference between actual and scheduled generation levels as described by the incremental power curve.

Therefore, when the projected wind speed is low, the need for up flexibility reserves is small because the maximum possible under-forecast error is also small; that is, between the scheduled output and zero generation. The potential over-generation forecast error, however, is relatively large because a much stronger-than-projected wind could result in considerably higher generation levels, up to the turbine capacity. The system-level flexibility reserve down requirement is dependent on the risk tolerance of the system operators. Very risk-adverse operators would reserve down flexibility capacity that is equal to the difference between the maximum rate output and the projected power production; that is, a zero risk. Lower levels of down flexibility pose risk levels that increase as the required flexibility reserve decreases. Very risk-adverse capacity requirements are relatively expensive because more capacity is reserved for flexibility reserves lowering the range of capacity that can be used for load following. Therefore, operators must weigh the economic costs of requiring various levels of reserves against grid risk exposure.

At the other end of the spectrum, under very windy conditions, the generation forecast error also tends to be small. Note that, as the power output approaches the wind turbine capacity, the incremental power output decreases and production levels flatten. If the wind is projected to be at a speed that produces the rated output level, but the actual wind speed is somewhat higher, the generation forecast error is zero. The forecast error continues to be zero through the cutoff wind speed. At very high wind speeds, the turbine cuts off energy production to protect the wind turbine. It is therefore not possible to over-forecast generation, and the need for flexibility reserves down is zero. If the actual wind speed is much lower than projected, then the corresponding output level is underestimated. Operators therefore schedule flexibility-up reserves under these circumstances at a level that is consistent with the operator risk tolerance.

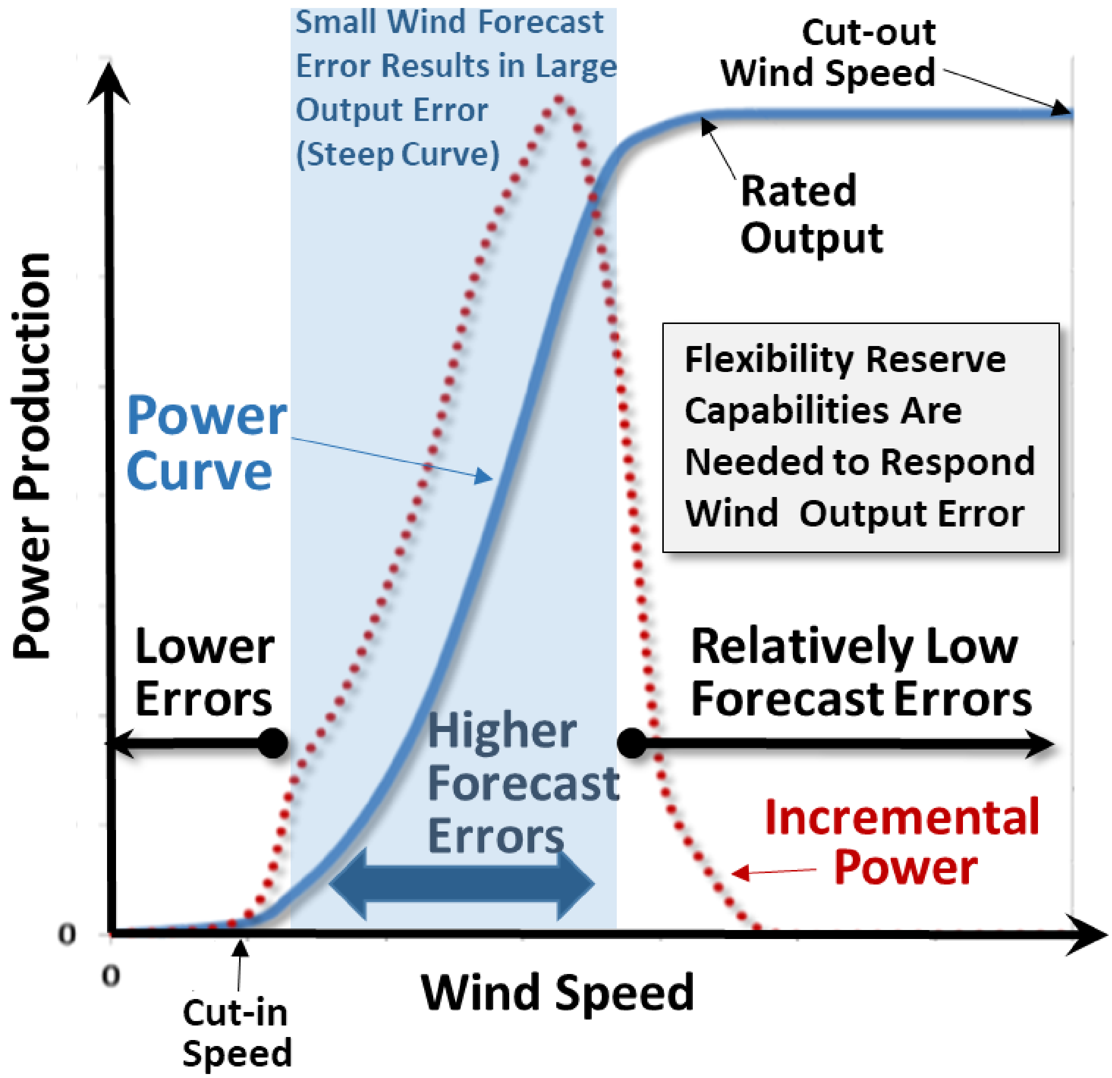


Figure 10-8 Wind Turbine Power Curve

When the wind is projected to be in the steep part of the wind turbine power curve, forecast errors tend to be significantly larger than for projections that are made under either low or high wind conditions. Wind-turbine power output forecast errors are larger because a small error in the projected wind speed corresponds to a relatively high-power output error, as shown by the incremental power curve.

Some BA operators resolve real-time energy imbalances, a portion of which may be attributed to VER forecast error, by utilizing resources that are solely within the BAA footprint. Other BAs are in a centralized market that resolves energy imbalances across multiple BAAs to take advantage of VER production diversity that occurs over a much larger footprint compared to an individual BAA. These markets also operate at dispatch intervals that are typically shorter than BAs that are not part of an organized market. Short intervals further reduce VER forecast error because lead-times between the scheduled deadlines and real-time operations are much smaller and dispatch adjustments are more frequent.

Operating in large footprints, such as those in a centralized market, provides an opportunity to increase hydropower economic value because it enables a hydropower resource to efficiently resolve energy imbalances over a larger geographical footprint. In addition, energy imbalances in a BA without hydropower resources that participates in a centralized market could potentially be resolved by a hydropower resource that resides outside of its boundaries.

In regions that have high penetration rates of VERs, especially of photovoltaic technologies, net load profiles display steep ramping during the midmorning hours, as VER power production rapidly increases, and in the late afternoon and early evening hours, as VER production quickly declines. Like flexibility reserves, hydropower value increases as the footprint in which it is operating expands.

As discussed in more detail in Sections 2.7 and 4.2, economic value can also be enhanced by taking advantage of hydropower diversity over larger footprints. For example, the potential for providing flexibility up reserves and ramping may be reduced/limited in one or more BAs that are under prolonged drought conditions, but other BAs in the footprint may have average or above-average hydropower conditions. By allowing hydropower operations to contribute in a larger grid, overall grid economics improve.

10.4 Wind Integration and Hydropower in the WACM BAA

Because the cost of VER integration is a function of the amount of flex-reg that is carved out of a hydropower plant, reserved capacity should ideally be as low as possible while maintaining a high level of grid reliability. Below is a discussion of how up and down flexibility reserves could be dynamically assessed to help achieve this goal.

Based on the TEPPC case, Argonne computed hourly wind forecast errors in the WACM BAA. One week of this projected future is illustrated in Figure 10-3. Forecast errors were estimated hourly for all VERs within the WACM footprint, employing a methodology that accounts for geographical VER diversity within the BAA. Hourly forecast errors were based on the persistence forecast method; that is, wind production in the next hour is projected to equal the current wind production level. WAPA also uses persistence forecasting for short-term daily Aspinall Cascade water inflow forecasting. It is therefore a methodology that WAPA uses in its daily business practices.

As explained in Section 10.3, flexibility reserve requirements are dependent on various grid attributes and the characteristics of the VER technologies that are in a BA. To analyze the need for flexibility reserves in WACM in 2020, Argonne created probability distributions of forecast errors under low, medium, and high wind speed conditions.

At low VER power production levels, when wind production in the BAA is in the 20- to 40-MW range, Figure 10-9 shows that there are many occurrences of small wind power production error. Using persistence forecasting, it obviously cannot be overestimated by more than 40 MW. However, if there is a big increase in wind speed, power production could theoretically increase in the next hour up to the total wind turbine capacity. This case would result in a very large under-projection of wind production. Because large increases in wind only occur on rare occasions, the distribution is skewed to the right (positive skewness). Therefore, under low wind speed conditions, the amount of WACM BA up-flexibility reserves needed to react to under projections is relatively small as compared to the regulation-down capacity that is need in response to over projections.

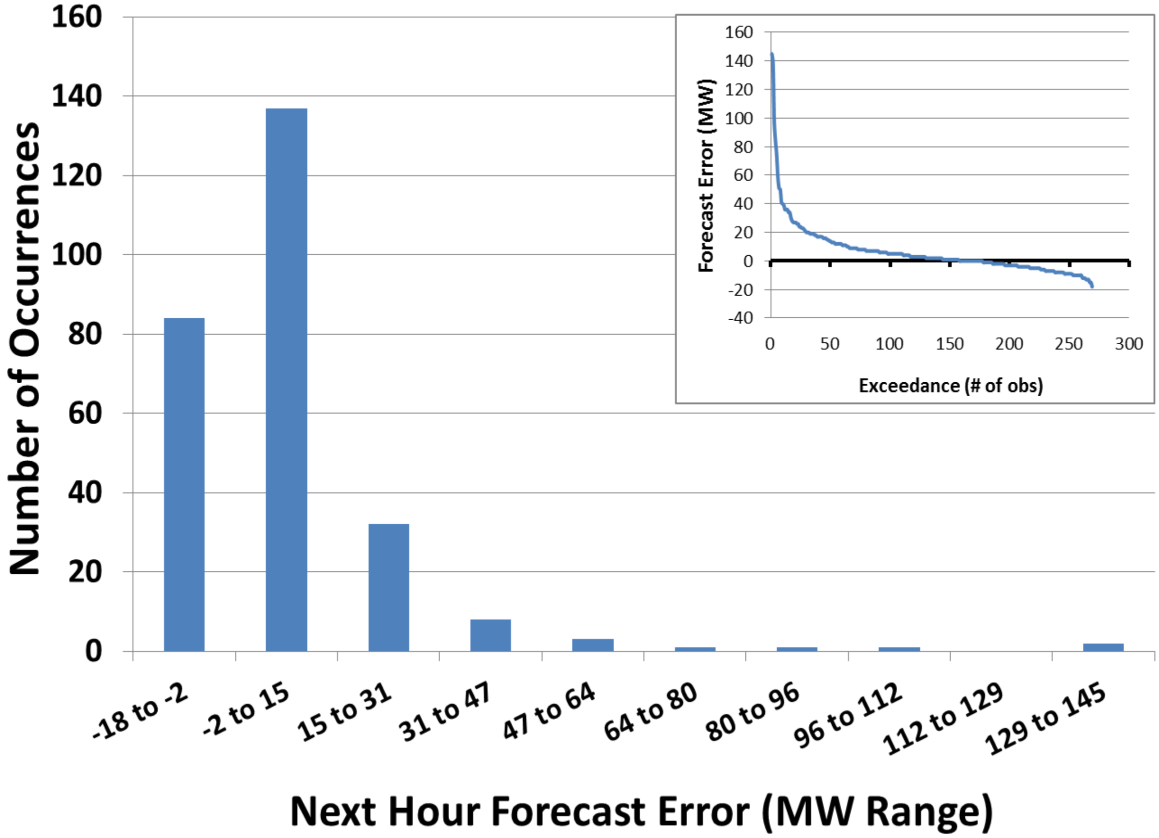


Figure 10-9 Forecast Error Distribution for the 20- to 40-MW Wind Production Class

Figure 10-10 shows that, when the wind production level is high—for example, in the 1,000- to 1,020-MW range—there are also many occurrences of relatively small wind power production error. In this case, the wind power forecast underestimate cannot exceed the wind capacity in the WACM BBA (i.e., 1,244 MW) minus 1,000 MW, resulting in 244 MW. On the other hand, if there is a sudden decrease in wind speed, power production could theoretically decrease to zero in the next hour, resulting in an over-projection of up to 1,020 MW.

A large decrease in wind production could also be caused by wind speed that goes above the turbine cut-off speed at which point the wind turbine shuts down. Because large reductions in wind occur only rarely, the probability distribution is skewed to the left. The amount of WACM flexibility reserve up capacity needed to react to under projections is relatively large compared to the regulation-down capacity that is needed in response to over-projections. Operators therefore could set flexibility up reserves at hydropower plants under these circumstances at a level that is consistent with the operator risk tolerance.

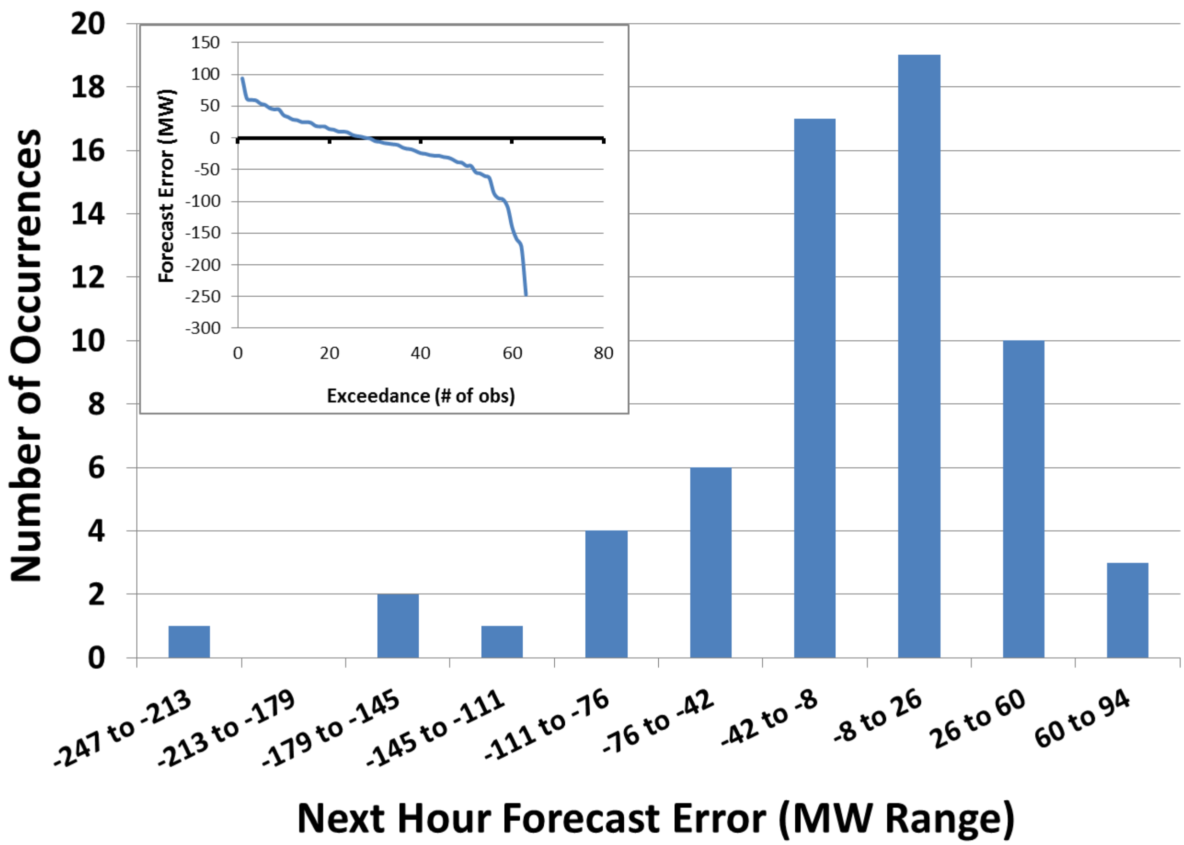


Figure 10-10 Forecast Error Distribution for the 1,000- to 1,020-MW Wind Production Class

The forecast error probability distribution function under moderate wind production levels, shown in Figure 10-11, is for wind generation levels between 540 and 560 MW. Note that, under these conditions, wind forecast errors are relatively large compared to low and high wind conditions. This is consistent with the shape of a typical wind turbine power curve (shown in in Figure 10-8), which shows that a small change in wind speed under both low and high production states yields only a relatively small output change. In contrast, in the middle of the turbine production curve, small changes in wind yield a much larger generation change. In addition, consistent with the shape of the wind turbine production curve, note the symmetrical error distribution centered at an approximate error of zero.

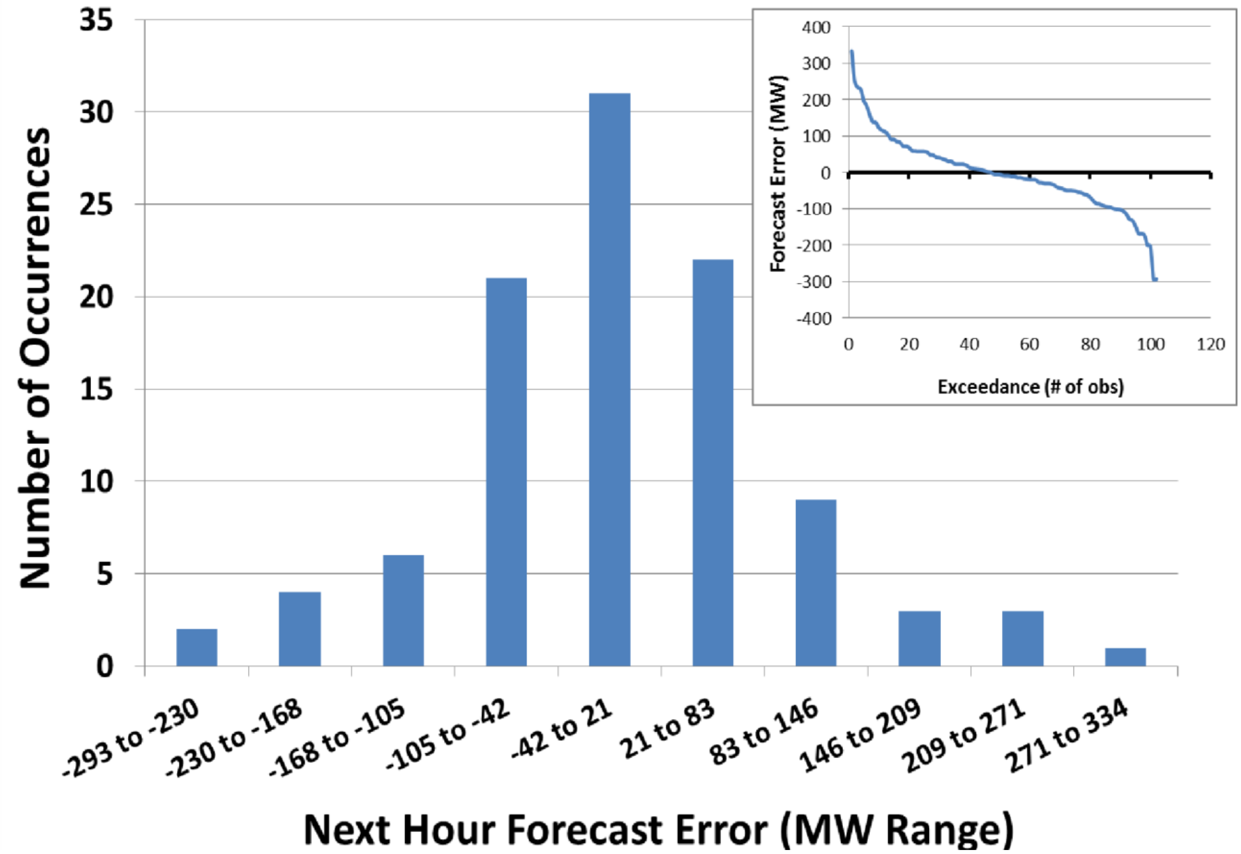


Figure 10-11 Forecast Error Distribution for the 540- to 560-MW Wind Production Class

10.5 Resolving Energy Imbalances with Hydropower

Energy imbalances in a BA are typically caused by several contributing factors, such as actual load and generation production levels that deviate from real-time schedules. These deviations are often the result of imperfect load projections and generator outages. Sometimes, individual sources of deviations compound the net deviation. At other times, deviations are in opposite directions, shrinking the net deviation. This is evident in Figure 10-12, which shows historical deviations in the WACM BA for a typical day in 2012 at a moment when VER penetration in the BAA was relatively small. As discussed in the previous section, these deviations are typically resolved in real time by federal hydropower resources that provide the BA regulation services.

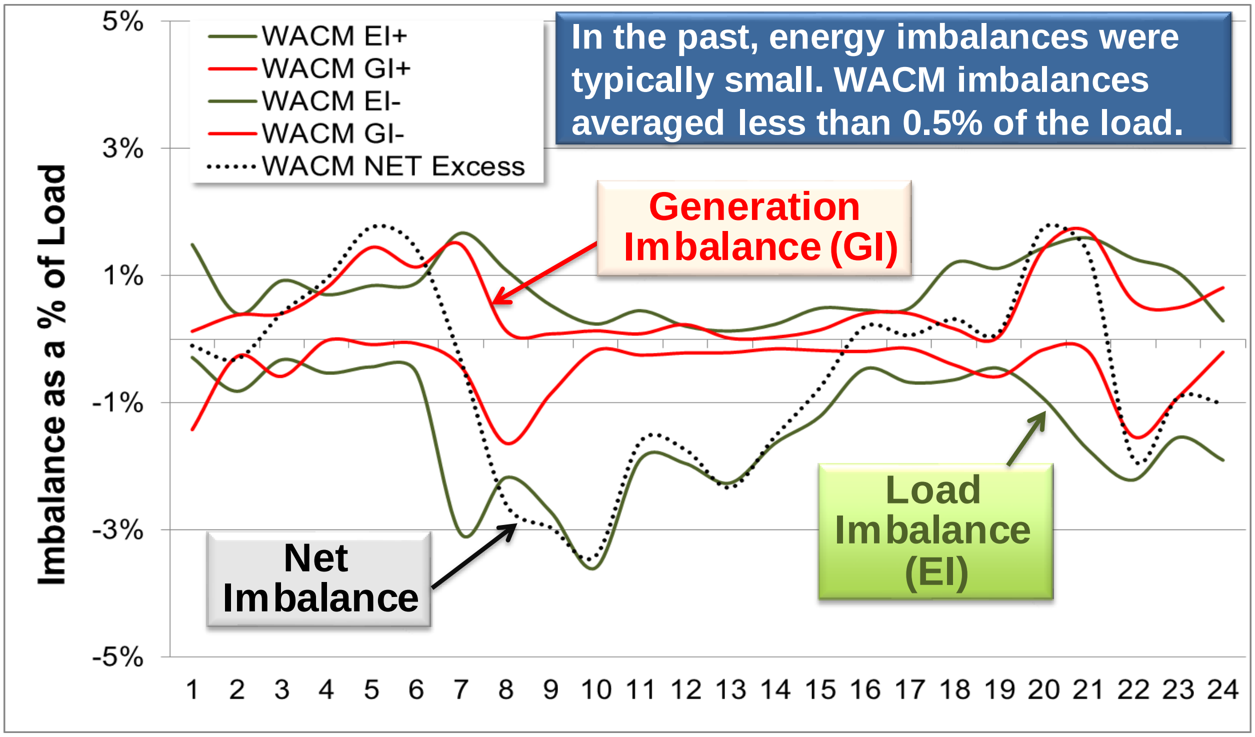


Figure 10-12 Illustrative Energy Imbalances for a Typical Day in the WACM BA, 2012

Since 2012, VER capacity in the footprint has substantially increased and is projected to continue growing in the future. Therefore, operational changes will need to be made for VER grid integration. One such potential change is to reserve capacity for flexibility services that enables a hydropower plant to respond to changes in VER generation levels. Typically, VER production deviations from scheduled levels is due to VER production forecast error. To keep the system in balance, hydropower plants that provide flexibility reserves react to VER deviations in the opposite direction. That is, hydropower plant output increases when VER production levels decrease below the scheduled level, and vice-versa. As shown in Figure 8-1, flexibility reserve capacity in both the up and down directions enables a hydropower resource to respond to both lower-than-forecasted/scheduled VER production (flexibility up) and higher-than-forecasted VER production (flexibility down). Both types of flexibility reserve narrow the load/price following range of the hydropower plant and reduces the amount of peak load that a hydropower plant can serve.

10.6 CAISO EIM

The WI has a wide range of markets including a bilateral market and a centralized market operated by CAISO that includes day-ahead, 15-minute, and 5-minute real-time energy markets. CAISO also operates an EIM since November 1, 2014. The initial EIM footprint included the CISO BAA and the two BAAs operated by PacifiCorp (PAC), which are PAC East (PACE) and PAC West (PACW).

The CAISO EIM is a voluntary balancing energy market that schedules resources every 15 minutes and optimizes generator dispatch within and between BAAs every 5 minutes without using regulation reserves. In addition to increasing economic efficiency, the intent of the EIM is to increase system reliability through heightened grid situational awareness and to facilitate VER integration by dispatching resources over a larger and more diverse footprint using a broad array of resources. In contrast, a BA operator that is outside of the EIM must resolve energy imbalances using resources that are solely within its own BAA with limited information about neighboring systems.

Participation in the CAISO EIM is open to all BA operators in the WI, subject to transmission access constraints. As of May 2018, the EIM had expanded to include a total of eight operating entities: APS, CAISO, Idaho Power, PAC, NV Energy (NVE), Powerex, Portland General Electric (PGE), and Puget Sound Energy (PSE). As shown in Figure 10-3, four additional entities have announced their intention to participate in the market in the future: Balancing Authority of Northern California (2019), Los Angeles Department of Power and Water (2020), Salt River Project (2020), and Seattle City Light (2020).[47] In addition, the Mexican grid operator El Centro Nacional de Control de Energía Baja Norte is currently considering future participation in the EIM.[48]

A BA participant of the CAISO EIM does not need to resolve energy imbalances in its own footprint because the centralized market resolves energy imbalances across multiple BAAs. This allows CAISO to take advantage of VER production diversity that occurs over a much larger footprint compared to the diversity that is exhibited in individual BAAs. These markets also operate at dispatch intervals that are typically shorter than the dispatch interval of BAs that are not part of the EIM. Short intervals further reduce VER forecast error because lead times between the scheduled deadlines and real-time operations are much smaller and dispatch adjustments are more frequent. In contrast, BA operators that do not participate in the CAISO EIM must resolve real-time imbalances by relying on only those resources within their own BAA footprint.

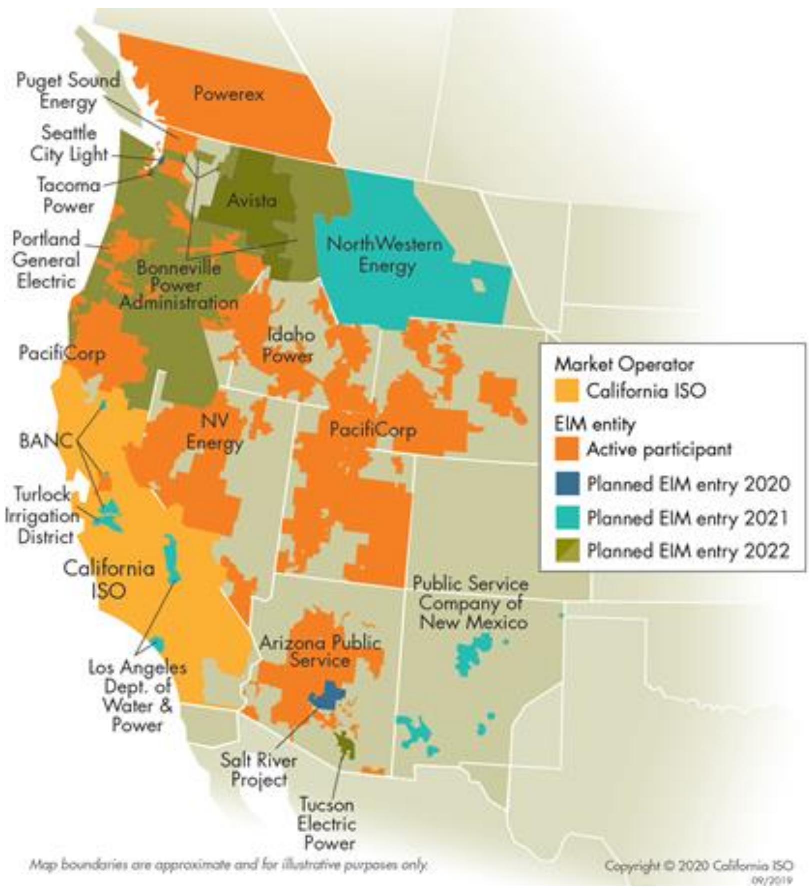


Figure 10-13 Current and Planned CAISO EIM Participants

Operating in large footprints such as those in a centralized market provides an opportunity to increase hydropower economic value because it enables a hydropower resource to resolve energy imbalances over a large geographical footprint. In addition, under an EIM energy imbalances in a BAA without hydropower

[47] Western Energy Imbalance Market, undated, "About," CAISO. https://www.westerneim.com/Pages/About/default.aspx.

[48] Market Watch, 2016, "Mexico grid operator CENACE to explore EIM participation for Baja California Norte, October 18. https://www.marketwatch.com/press-release/mexico-grid-operator-cenace-to-explore-eim-participation-for-baja-california-norte-2016-10-18-13160112.

resources that participates in the EIM could potentially be resolved by a hydropower resource that resides outside of its boundaries. For example, even though it has no hydropower resources, some of the energy imbalances in the AZPS BAA may have been resolved by the CAISO EIM after it joined the market on October 1, 2016.

Instead of resolving AZPS BAA energy imbalances due to solar generation deviations (Figure 10-6 and Figure 10-7) using resource solely within its footprint, real-time and 5-minute imbalances are currently resolved by the much larger CAISO EIM footprint.[49] The EIM balances AZPS loads and resources in concert with those of other EIM participants through generator dispatch across multiple BAAs every 5 minutes. This includes BAAs with substantial hydropower resources, such as the CISO BAA, which has the second-largest amount of hydropower capacity within the WI.

In addition to the EIM, day-ahead and real-time markets bolster hydropower economic value by taking advantage of hydropower diversity over larger footprints. As previously discussed, the potential for providing energy and load following may be reduced/limited in one or more BAs that is under prolonged drought conditions, but other BAs in the larger footprint may have average or above-average hydropower conditions.

By allowing hydropower operations to contribute to a larger grid, hydropower can also assist BAs in which VERs have high penetration rates. This may be especially helpful when photovoltaic technologies create net load curve shapes, such as those exhibited by CAISO and APS that have steep ramping during the midmorning hours when VER power production rapidly increases and in the late afternoon and early evening hours as VER production quickly declines. In these cases, flexible hydropower resources would be able to peak-shave net loads during the afternoon/evening peak allowing operators to shut down units during the middle of that day without restarting them a few hours later.

[49] CAISO, 2016, "Arizona Public Service, Puget Sound Energy enter the EIM: ISO real-time market is now providing low-cost energy to consumers in eight western states," News Release, October 3. http://www.caiso.com/Documents/ArizonaPublicService_PugetSoundEnergyEnterTheEIM.pdf.

This page left intentionally blank.

11.0 Computing Hydropower Energy Economics Based on Centralized Economic Dispatch versus a Decentralized Financial Paradigm

An economic analysis is based on societal costs and benefits. In contrast, a financial analysis focuses on the revenues and costs accrued by a particular entity including transfer payments, such as monies exchanged for power transactions, taxes, and insurance. It also includes payments made by individual entities for previous investments. In an economic analysis, these transfer payments among entities are excluded because the total net change to social welfare of these transactions is zero; for example, the amount paid by an entity that purchases power equals the amount received by the selling entity. Also excluded from economic costs are past investments (i.e., sunk investments), such as those to construct power plants because these expenditures have already been incurred on society and cannot be recovered.

Precisely computing hydropower economic benefits on large footprints such as the WI is difficult because the problem is very large and complicated. Methods vary widely, but typically involve the use of either historical market prices or production-cost models. Production-cost models that minimize grid economics are often used to estimate systemic benefits of hydropower operations at an interconnection level, but many simplifying assumptions/modeling techniques are used to fill in data gaps and solve the unit-commitment/dispatch problem in a reasonable amount of time. Another approach assumes that the marginal economic value of energy and ancillary services is equal to actual/observed market prices and does not change as a function of hydropower plant operations. Each approach has specific strengths, but both lead to imprecise answers.

11.1 Centralized Economic Dispatch

Because market prices may not always reflect marginal economic value, production cost models are often used to compute the economic value of hydropower and/or the cost of changed hydropower operations. Production-cost models estimate supply resource generation levels over a specified time and compute associated costs. One advantage of these sophisticated grid-level modeling tools is that they account for interactions among all system components. These models also simultaneously consider the impacts of individual entity production on all grid components and entities.

The centralized approach takes the point of view of a hypothetical central authority that makes decisions that minimize the total costs of an entire system. Depending on the model settings, resource utilization and costs are computed at various levels of granularity ranging from minutes to a year. Some models are probabilistic and utilize load duration curves (LDCs) that essentially convey the amount of time when a specific load level is exceeded. For example, the peak load is never exceeded and the minimum load is always exceeded. Either units or unit blocks are then loaded under the curve based on merit order (e.g., lowest to highest production costs). To account for unit forced outages, either the unit capacity is de-rated or the LDC is convolved such that unit outages are accounted for by adding additional loads to the LDC after each unit/block has been loaded into the curve. The amount of load added equals the capacity of the unit or block times the applicable forced outage rate. The LDC is modified such that when a "probabilistic" outage occurs, units with a lower merit order must serve the loads that the unit forced out of service could not.

The advantage to probabilistic production costs models is that they explicitly account for the impacts of all possible outage situations on production costs. They explicitly model the fact that regardless of the amount of firm capacity that reside in the grid and level of capacity reserves, there is a nonzero probability that a reduction in hydropower energy cannot always be replaced, either triggering an unserved energy event or an increase in unserved energy. The probability is nonzero because there is always a chance that a combination of load and generating unit outages will occur that prevent some or all of the lost hydropower energy from being replaced.

When the system capacity is long (i.e., resources are above the target RM), the probability that all the lost hydropower energy will not be replaced is relatively small in comparison to systems that are capacity short. In the near term, therefore, hydropower capacity and energy production not only decrease economic costs, they also increase grid reliability.

One problem associated with probabilistic dispatch models is that chronological events are lost and spatial constraints/interactions (e.g., locations and transmission) are ignored or represented very simplistically. Therefore, time-dependent constraints such as unit commitments and ramp-rate limits are not explicitly modeled and bulk power transfers on interties among BAAs are at best based on rough approximations. VER energy production is typically represented by first subtracting VER hourly production from loads and then constructing the initial LDC from the net load. In addition, grid contributions from limited energy resources such as hydropower generation are computed externally. Hydropower blocks (typically base and peak) are then fit under the convolved LDC such that the amount of load that is served by hydropower equals the assumed amount.

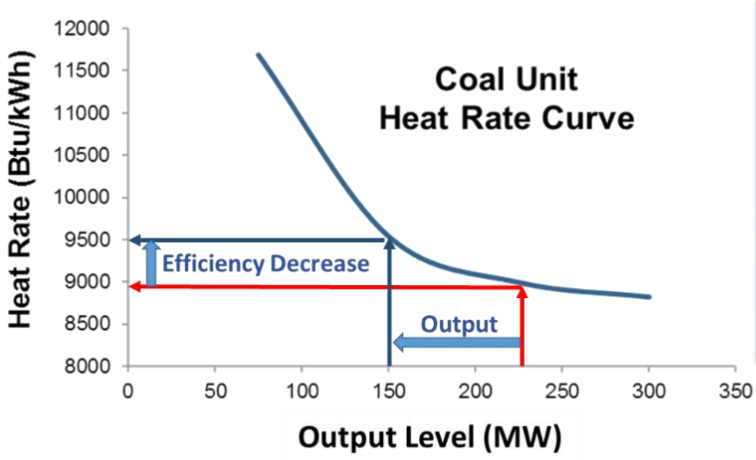
Another category of production cost models explicitly simulate chronological unit commitments and dispatch. Many also incorporate a representation of power transfers among zones/regions, such as BAAs based on the grid high voltage transmission network, or an "equivalent" transmission topology. These algorithms are generally more detailed than probabilistic models, but the dispatch is usually based on either a deterministic set of forced outages that represent a time series of "typical" outages or unit capacities are de-rated. The computation of key reliability parameters—such as energy not served (ENS) and LOLP—therefore during all critical load periods do not include a range of extreme outage cases that typically cause most supply shortages.

Typically, the dispatch routine incorporated into IRP models tends to operate at a relatively coarse level of fidelity (i.e., spatially connectivity among large aggregate areas with long time steps) because expansion tools compute dispatch economics for a multitude of candidate expansion states over the duration of the modeled timeframe, as previously described in Section 3. In particular, the fidelity of hydropower operations is at a coarse level of granularity because complex interactions among water, power, reservoir limitations, the environment, and downstream water delivery obligations are difficult and computationally expensive to solve. If ensembles of hydropower productions are evaluated for each expansion pathway, the number of dispatch runs are greatly expanded. Once the model finds the optimal expansion pathway, a more detailed dispatch can be performed on the final (least-cost) pathway under a select set of hydropower conditions to refine estimates of hydropower production on dispatch economics.

Although current state-of-the art tools are sophisticated, there are major modeling challenges associated with the simulation of the three U.S. interconnections that make precise measurements of hydropower values very difficult. Models that optimize the dispatch of large interconnections make a myriad of grid modeling simplifications in order to make the problem tractable and solve it in a reasonable amount of time. In addition, model accuracy is rooted in the veracity of site-specific data. These shortcomings also make it difficult to accurately measure grid operations reactions to hydropower changes and therefore economic values. Economic measurement when applied to large-scale models over long periods should therefore be viewed as an approximation of reality.

For example, models typically use discrete blocks to approximate the implication of the heat rate curve on a unit's marginal production cost. This block representation is the norm for state-of-the-art production-cost models because it enables linear programming (LP) and mixed integer LP (MILP) software to solve large dispatch problems in a reasonable amount of time. Furthermore, marginal production costs for blocks loaded after the must-run base block are typically required to increase as a function of increasing unit output. This is counter to the profile of typical heat rate curves.

Block representation also has a lower level of fidelity than a continuous nonlinear function such as the one shown in Figure 11-1.[50] As illustrated in this hypothetical, but nonetheless realistic, example, a 75-MW decrease in the steam coal-fired unit's output level from 225 to 150 MW would increase the unit's heat rate by about 550 Btu/kWh. This results in an increase of both consumption and fuel costs of roughly 6% per megawatt-hour of energy produced. As shown in the right-hand side of the figure, changes in efficiency as a function of output levels for other technologies are even larger. However, the economic impacts become more complex when two or more units are taken offline in order to accommodate hydropower power production.



Load	Partial Load Penalty (%)			
	Coal (ST)	Gas (CC)	Gas (CT)	Oil (CT)
25 %	34.19	44.84	64.97	113.46
50 %	9.06	13.20	17.97	26.82
75 %	2.24	3.82	4.76	5.27
100 %	0.00	0.00	0.00	0.00

Figure 11-1 Hypothetical Heat Rate (measure of unit efficiency) as a Function of Thermal Unit Output

Because the operating characteristics within each block are assumed to be homogeneous it can produce a lumpy supply curve composed of relatively large, flat sections separated by abrupt price changes. In general, the fewer the plants in the system being characterized, the more likely it is that relative greater levels of lumpiness and discontinuities will exist in the supply function for the system. Another factor that contributes to a lumpy supply curve is the granularity of data used to represent individual generating units. Unit-specific information regarding heat rate curves and other unit characteristics, such as fuel prices and forced outage rates, are typically proprietary.

As an approximation, generic attributes for various classes of units are typically used as model input data. As a result, two or more units in a geographic region (e.g., a state) are frequently assigned identical production costs when, in reality, costs differ. The lumpy nature of the modeled production cost curve at times results in a zero or very small LMP change when hydropower energy is injected into the grid. In other situations, it results in an exaggerated price change as operations transverse a segment of the lumpy curve that has an abrupt price change. This lumpy profile is clearly noticeable in the supply curve in

[50] A smooth industry supply function is a theoretical construct provided in economic texts. This theoretical construct is employed primarily to facilitate the use of calculus for optimization. Supply functions for a single thermal plant may actually have discontinuities simply because there are likely to be multiple units at the plant and each unit may have different operating characteristics.

Figure 11-2 for the CAISO BA footprint that was estimated by the Asea Brown Boveri Ltd. (ABB) Velocity Suite software that primarily uses publicly available data/information.

Other difficulties associated with modeling the WI for long-term analyses consist of, but certainly are not limited to, the following:[51]

1. The WI operates over several U.S. states and three countries with varied jurisdictional requirements;
2. Part of the system operates in organized central markets (e.g., CAISO), whereas other portions operate in a bilateral market;
3. A large fraction of WI loads are supplied by hydropower plants, many of which are subject to environmental operating criteria that are challenging to model (even on a site-specific level);
4. There is a lack of unit-specific information on fuel prices and heat rate curves;
5. There is insufficient data on bus-level loads;
6. It is necessary to employ simplifications of a large and complicated transmission system;
7. There is a lack of information on resource availability (e.g., unit outage and transmission line outages);
8. There are forecast errors associated with loads, hydropower inflows, and VERs (i.e., wind and solar) energy production; and
9. There are complex interactions among entities making autonomous decisions under uncertainty based on limited information about the interconnection.

Although models do not provide precise numerical values, relative magnitudes, directions, and operational reactions displayed over an ensemble of model outcomes can provide valuable insights into the economics of hydropower to the grid.

[51] T.D. Veselka, L.A. Poch, and A. Botterud, 2012, *Review of the WECC EDT Phase 2 EIM Benefits Analysis and Results Report*, ANL/DIS-12-2, Argonne National Laboratory, Lemont, IL, April. http://www.ipd.anl.gov/anlpubs/2012/04/73032.pdf.

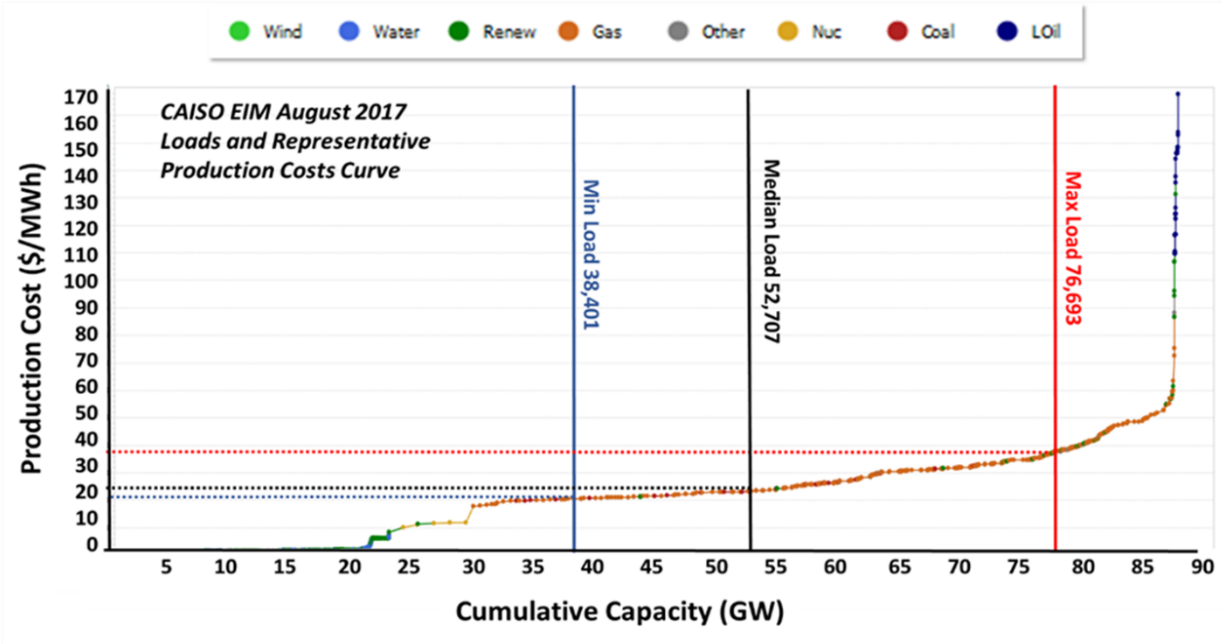


Figure 11-2 CAISO Supply Curve Constructed by the BAA Velocity Suite, August 2017

11.2 Decentralized Financial Decisions

Because an entity that owns and operates a hydropower plant has objectives that typically differ from an entity that maximizes grid economics, actual hydropower operations may differ from the optimal economic operational pattern. For example, if an entity's goal is to maximize revenues from energy sales, then the hydropower plant operation schedule would concentrate its discretionary energy production in those hours of the day that have the highest prices, as illustrated in Figure 11-3. In a small system such as the one illustrated in the peak-shaving example in Figure 4-25, the best financial solution may not produce the highest economic value because myopic financial decisions that are based primarily on the objectives a specific entity do not consider the fact that hydropower operations impact the costs and operation of other grid components. As previously discussed, this same myopic view may also cause suboptimal economics in which cascaded hydropower plants are owned by two separate entities.

Assuming market energy prices reflect marginal economic costs, in a large system, such as the U.S. Eastern and Western interconnections, the generation pattern in Figure 11-3 may not only be financially optimal for the owner, but also yield a result that is at or near the one that yields the highest economic value. This is because the hydropower operation of a single plant usually (but not always) has a tiny (if any) effect on the marginal cost of energy. That is, when hydropower displaces generation from the marginal cost unit, the one below it in the merit order dispatch is often very similar, albeit slightly lower, than the cost of the displaced unit; that is, the supply curve tends to be fairly flat, especially for small changes. However, congestion and energy displacement at steeper portions of the supply curve (i.e., super peak period) may yield larger grid price reactions.

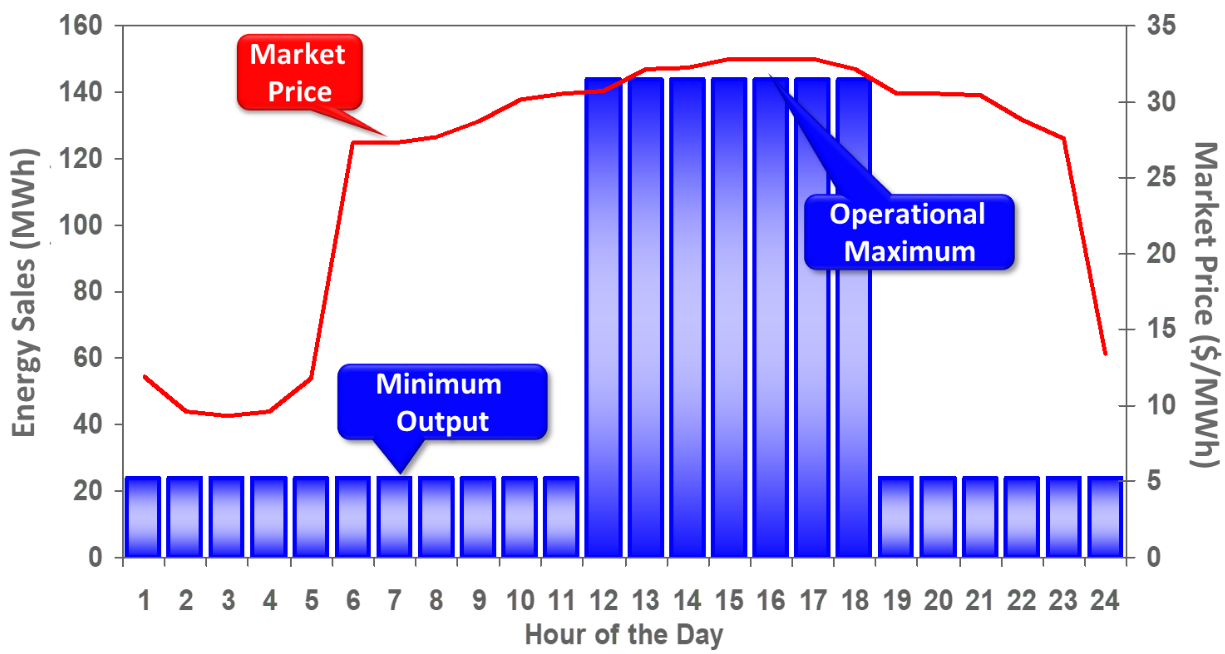


Figure 11-3 Hydropower Operations that Maximize Financial Income

It is also important to note that whereas hydropower operations at a single resource may have little impact on the marginal value, together all hydropower plant operations may have a large impact on market prices—especially in grids such as the WI, which account for a significant share of the power capacity and energy mix.

In theory, under perfect market conditions in which all participants behave rationally and no entity has market power, all power resources are bid into the market at actual production cost. As a result, LMP s would equal system-level marginal economic costs. However, U.S. ISO and RTO markets do not require suppliers to bid power resources at marginal production costs, and the actual behavior of U.S. markets suggests that market participant bids do not always reflect incremental generation costs. For instance, in ERCOT, under scarce conditions, the bid in the energy market can reach up to $9,000 per megawatt-hour, which is far above the marginal production cost of the peaking generators.

In addition to financial drivers, markets are influenced by the collective bidding behaviors of individual market participants, each of which make autonomous decisions in their own self-interest. Individually, each participant makes bid-related decisions under uncertainty with limited situational awareness of the grid. Because individual utility bidding decisions are often motivated by company-level financial objectives, U.S. ISO and RTO LMPs and ancillary service prices therefore do not always reflect true grid economics. For example, during the California electricity crisis, market manipulation played a dominate role in the eight-fold increase in wholesale prices from April to December 2000. Many issues associated with the crisis have been rectified, but markets are still not perfect.

More recently, an October 2016 FERC staff report entitled “Common Metrics Report” discussed price-cost markups and compared price-based offers to cost-based offers of marginal units. Low markups suggest competitive market performance. In general, over a 5-year period from 2010 to 2014, markets on average showed modest price markups. During this 5-year period, CAISO reported a negative annual average price markup every year, ranging from very close to zero in 2012 to negative 4.8% in 2014. Negative values are reported because the default energy bid in the CAISO market includes a 10% markup, and many resources choose to bid below the default level. Adjusting for the CAISO 10% markup default the CAISO markup from actual costs ranged from about 5.2% to just under 10%. Other markets show smaller markups. For example, in 2014, the annual average markup in SPP was just under 5.0% in its first year of operation. MISO reported markups that were consistently around 1.0%. Finally, NYISO in some years reported annual average markups that were negative (approximately negative 1.5%).

11.3 Market Simulation Models

Conventional optimization techniques used for grid analysis are based on a single decision maker that maximizes or minimizes a particular objective. Alternatives to centralized economic dispatch modeling include models such as the Argonne Electricity Market Complex Adaptive System (EMCAS)[52] tool, which simulates the autonomous decision making of many individual entities that compete in an open market. In this modeling configuration, many entities, each with a different set of unique objectives, make simulated decisions based on decision-making rules and behavioral patterns that can draw on an array of historical information (e.g., past power prices and patterns) and projected data to support entity decision processes. Each entity learns from previous simulated experiences/outcomes and changes its behavior when future opportunities arise. That is, as the simulation unfolds, an entity can adapt its strategy, based on the success or failure of previous actions. For example, instead of simply bidding production costs, entities with supply resources may bid energy into the market at any price that is allowed under market rules.

EMCAS simulates six decision levels/timeframes, ranging from hourly dispatching to long-term planning. At each decision level, simulated entities must make a set of decisions, including determining electricity consumption (customer agents), unit commitment (generation companies), bilateral contracting (generation and demand companies), and unit dispatch (ISO/RTO agent). EMCAS has several interaction layers that provide the environment for the agents to operate in. This environment is typically multidimensional; that is, entities operate within a number of interconnected layers, including a physical layer, several business layers, and a regulatory layer. EMCAS can simulate various market operating rules established by a regulator.

Models that simulate individual behaviors typically do not produce a single answer. Instead, they produce a range (or distribution) of plausible results from which modelers/analysis learn about the evolution of potential entity-level behaviors under various conditions. Such models are useful, for example, as “electronic” laboratories in which to test how various market rules will influence market prices and price volatility.

11.4 Comparative Analysis Method

As previously discussed several sections above, hydropower economic value is often based on a framework that compares the costs of a counterfactual case to a benchmark (e.g., actual) or status quo case. A methodology that generates absolute values of grid costs can be based on economic production-cost model, market simulation models, or historical market prices.

One of the strengths of a comparative analysis is that, when carefully applied, the final economic result is more accurate than the absolute economic value of the individual model runs because errors due to model simplifications affect both cases. Modeling errors therefore may be eliminated. In some situations, however, modeling errors are much larger in one case than in another due to differences in the structure

[52] Center for Energy, Environmental & Economic Systems Analysis, undated, “Electricity Market Complex Adaptive System (EMCAS): A New Long-term Power Market Simulation Tool,” Decision and Information Sciences Division, Argonne National Laboratory. https://ceeesa.es.anl.gov/pubs/60358.pdf.

and characteristics of the compared cases. For example, in a comparative economic analysis of generating facilities, assuming an incorrect capacity level would significantly affect modeled economics for a case that assumed high operational flexibility.

This same incorrect assumption, however, may have a miniscule effect (if any) on modeled economics under a case that has no operating flexibility. Modeling error may also be a function of hydrological condition. For example, there may be little or no errors under very high hydrological conditions in which the plant continually operates at is physical maximum output. On the other hand, hydropower conditions that allow for high generation fluctuations over time may produce results with much larger modeling error.

The disadvantage of comparative analyses is that the unequal effects of model inaccuracies among alternatives are not quantified, which could potentially lead to a false sense of model accuracy. It is therefore critical for modelers to identify and fundamentally understand the key variables that influence the differences between with- and without-hydropower cases.

Although models are only approximations of reality, carefully applied comparative analyses provide valuable new insights into hydropower economics in terms of relative magnitudes and direction, such as the relative difference in hydropower economic energy value under various hydrological conditions. It is therefore important that domain experts that have an in-depth knowledge of the system be deeply involved in applying the tools, assessing results, and drawing conclusions based on the model outputs in the context of methodology/model strengths and weaknesses.

12.0 Hydropower Impacts on Energy Market Prices/Economic Marginal Values

This section examines the impact of hydropower operations on grid market prices and marginal economic costs. This is one of the significant challenges associated with estimating economic value, especially when using historical market prices.

As shown by the supply curve in Figure 4-24, hydropower generation reduces the marginal production cost of the power system/grid. The more output from hydropower, the lower the cost. However, because the supply curve is convex upward, the incremental reduction in marginal prices tends to decrease as a function of lower demand and increasing hydropower energy production. These impacts are in part supported by an examination of average monthly energy prices in the CAISO NP-15 zone. The zone footprint is depicted in Figure 12-1.

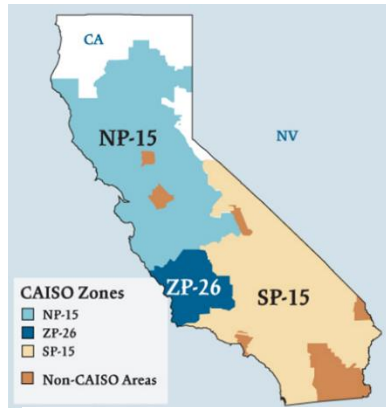


Figure 12-1 CAISO Zones

Average monthly energy prices illustrated in Figure 12-2 show that, in general, CAISO NP-15 average monthly day-ahead and real-time energy prices (primary y-axis) have a pattern that is similar to California natural gas prices (secondary y-axis). Note also that monthly day-ahead and real-time prices are similar. This correlation occurs because most of the time in the WI, the marginal generator (i.e., the one that sets the price/incremental value), is a gas-fired technology. However, there are times when electricity prices deviate from the natural gas price pattern. For example, during the spring of 2011 natural gas prices increased slightly while CAISO energy prices experienced a steep drop. This coincides with an off-peak load period with exceptionally high WI hydropower production (Figure 4-12), especially in the Pacific Northwest.

To examine the interplay among CAISO energy market prices, hydropower production, and natural gas prices, a regression analysis of monthly natural gas and energy prices was performed. Figure 12-3 shows the correlation between monthly average day-ahead energy prices and natural gas prices (left side of the figure). Using a third-order polynomial curve, the coefficient of correlation between the two commodities is a modest 0.54. The correlation was slightly weaker (i.e., 0.48) when a regression analysis was preformed on natural gas and real-time CAISO prices (right side of the figure).

Adding renewable production, including hydropower, to the regression analyses increases the overall accuracy of the fit. This was done through the use of a two-dimentional polynomial regression analysis and was performed for first-, second-, and third-order polynomial fits (the third-order regression surface and feed data can be observed in Figure 12-4). While it is impossible to directly compare global model performance statistics between the Natural Gas Exclusive model and the Renewable/Natural Gas models due to a combination of statisical and multi-dimentional dynamics, it is possible to aggrigate a broad range of individual performance metrics to demonstrate overall improvement. The most basic of these is average absolute percent model error, which was reduced from 13.5% to 11.3% in the day-ahead model and from 14.% to 12.2% in the real-time model. This performance improvement is most notable in the reduction in instances of significant error (greater than 30% error) for the day-ahead model, which decreased from 9% of predictions to 3% of predictions (a reduction in significant error was also observed in the real-time predictions, from 11.4% to 6.8%).

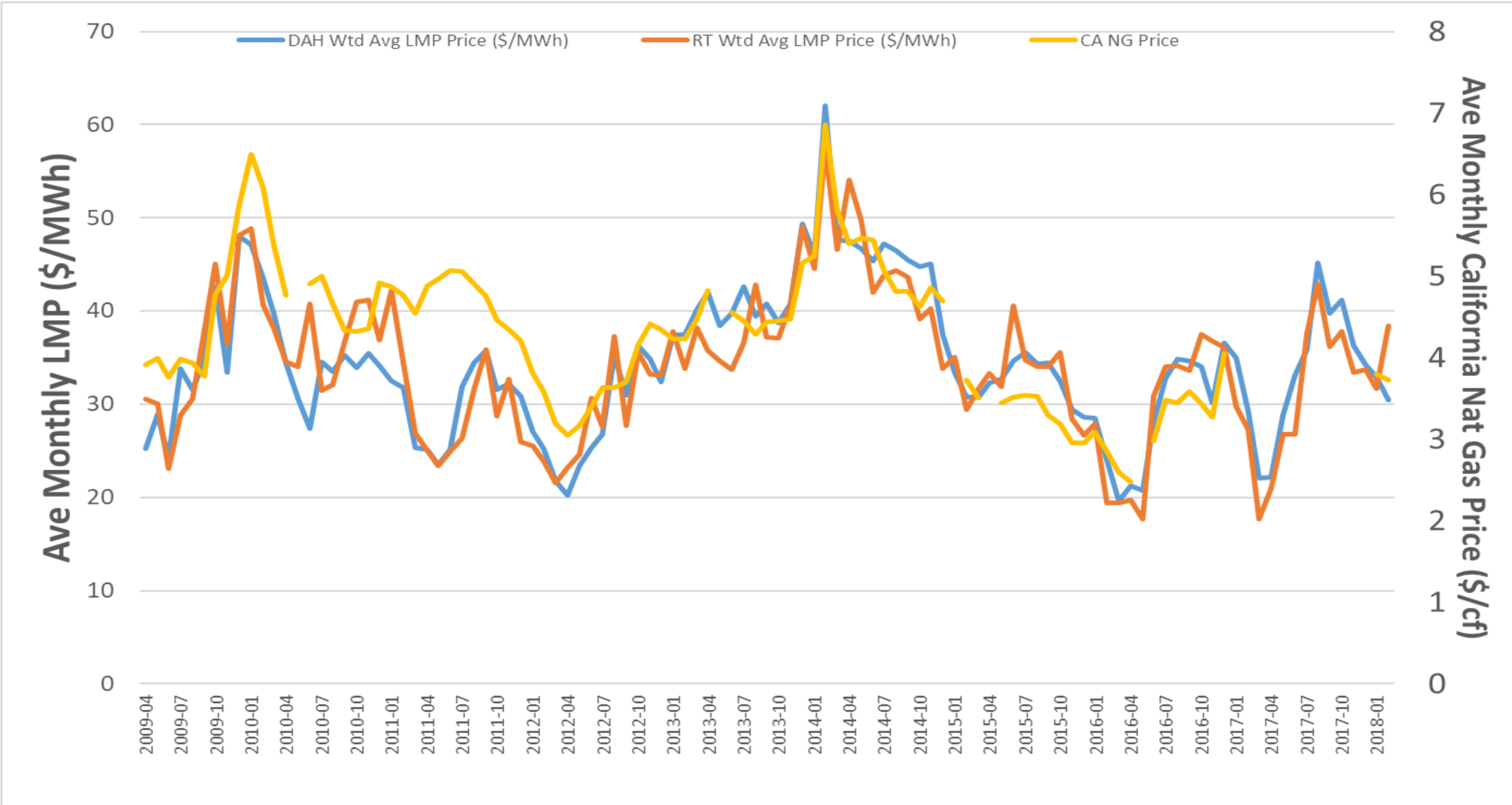


Figure 12-2 NP-15 Average Monthly Day-ahead and Real-time Prices of Energy and California Natural Gas Prices

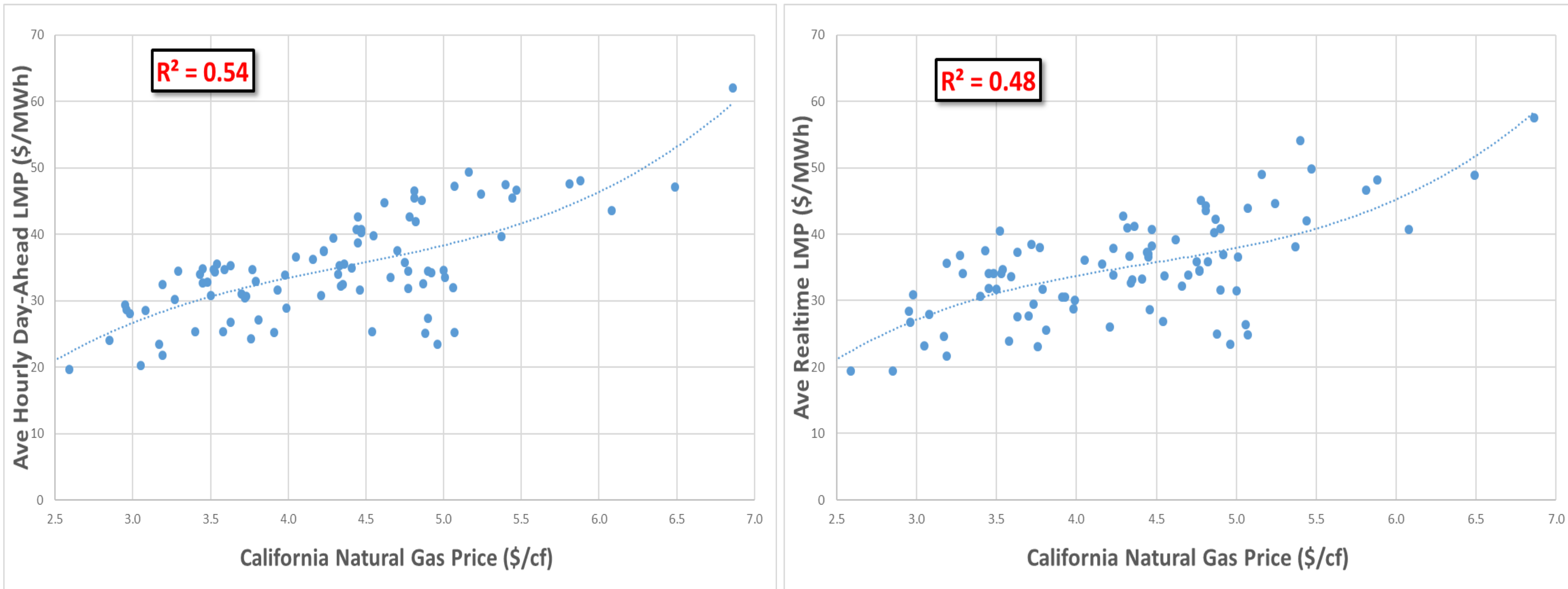


Figure 12-3 Results of Regressions Analyses of Using Natural Gas Price as an Explanatory Variable for CAISO NP-15 Zonal Energy Prices

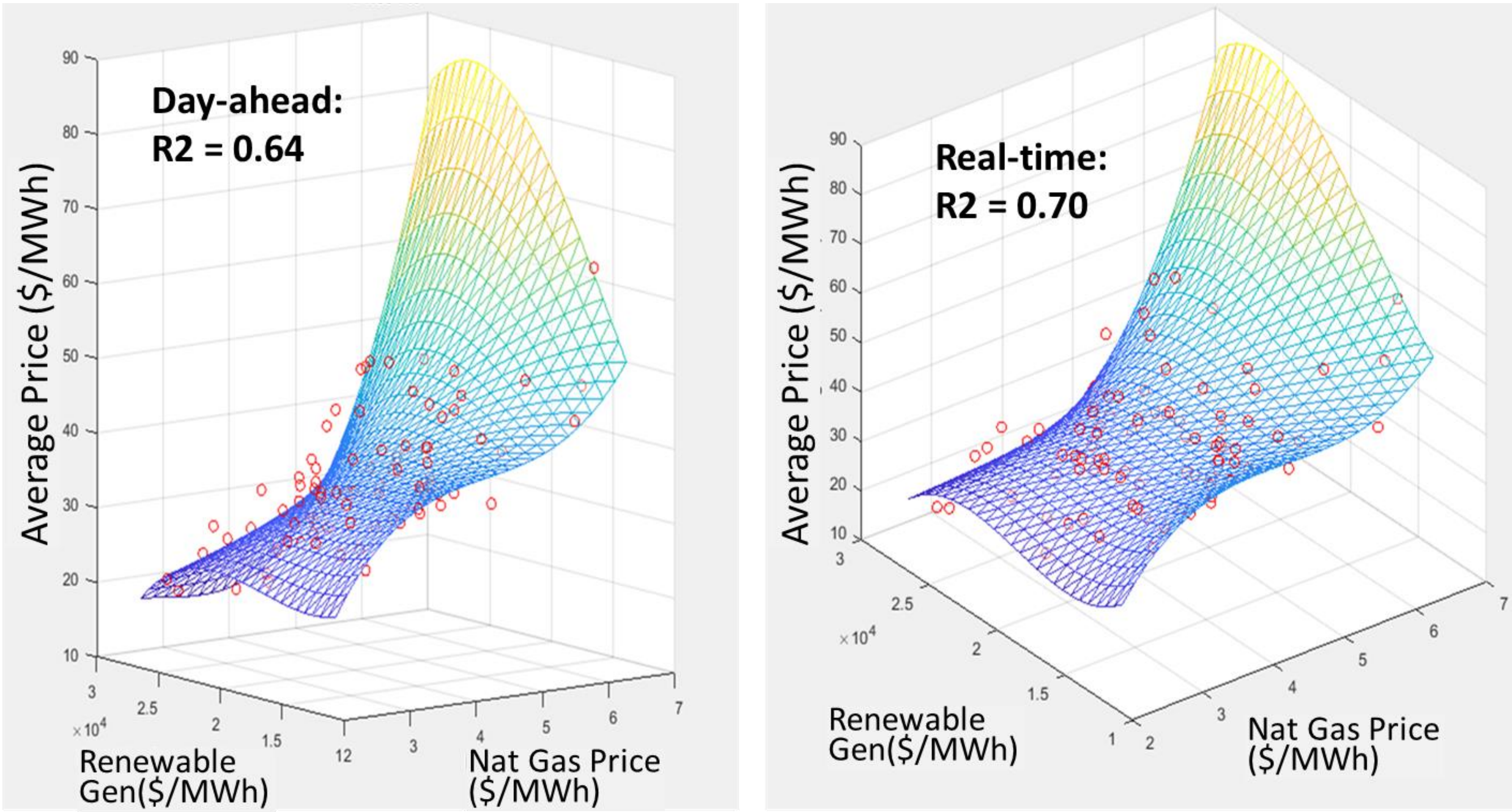


Figure 12-4 Results of Regressions Analyses of Using Both Natural Gas Price and Renewable Energy Production as Explanatory Variables for CAISO NP-15 Zonal Energy Prices

12.1 Hydropower Short-run Impacts

This simple regression analysis also suggests that in a competitive market that uses LMPs as a payment mechanism, the $/MWh value of hydropower deceases as a function of higher renewable energy production; in the WI, this includes major contributions from hydropower. A more detailed analysis conducted by Argonne for WAPA provided more evidence of this relationship between hydropower generation and market prices.

Argonne ran the AURORA production cost model under two sets of bookendwhe environmental operating criteria at GCD. The first set, the modified low fluctuating flows (MLFF) criteria, is based on the GCD 2006 ROD. The second assumes nearly year-round stead flow (YRSF); that is, nearly constant water releases and generation from the GCD hydropower plant throughout the year. Figure 12-5 is a scatter plot of simulated 2017 GCD generation differences between the MLFF and YRSF criteria and grid reactions in terms of LMP changes at the GCD. It shows that simulated economic price and generation differences are inversely related. This line can be used as a very general rule-of-thumb price reaction function. It shows that a GCD generation decrease of 1 MWh results in a simulated LMP decrease of $0.00188 in the GCD zone/point. However, note that this ballpark guideline is imprecise, especially for larger generation changes when the range of price reaction outcomes expands as a function of generation changes.

The yellow dashed line in Figure 12-5 is a polynomial regression fit. Note that it is similar to the linear regression fit, except that polynomial fits tend to have slightly smaller negative LMP reactions to an increase in YRSF generation; hourly generation decreases tend to have a very slightly larger positive LMP response. This result is consistent with the WI production-cost curve in Figure 11-2.

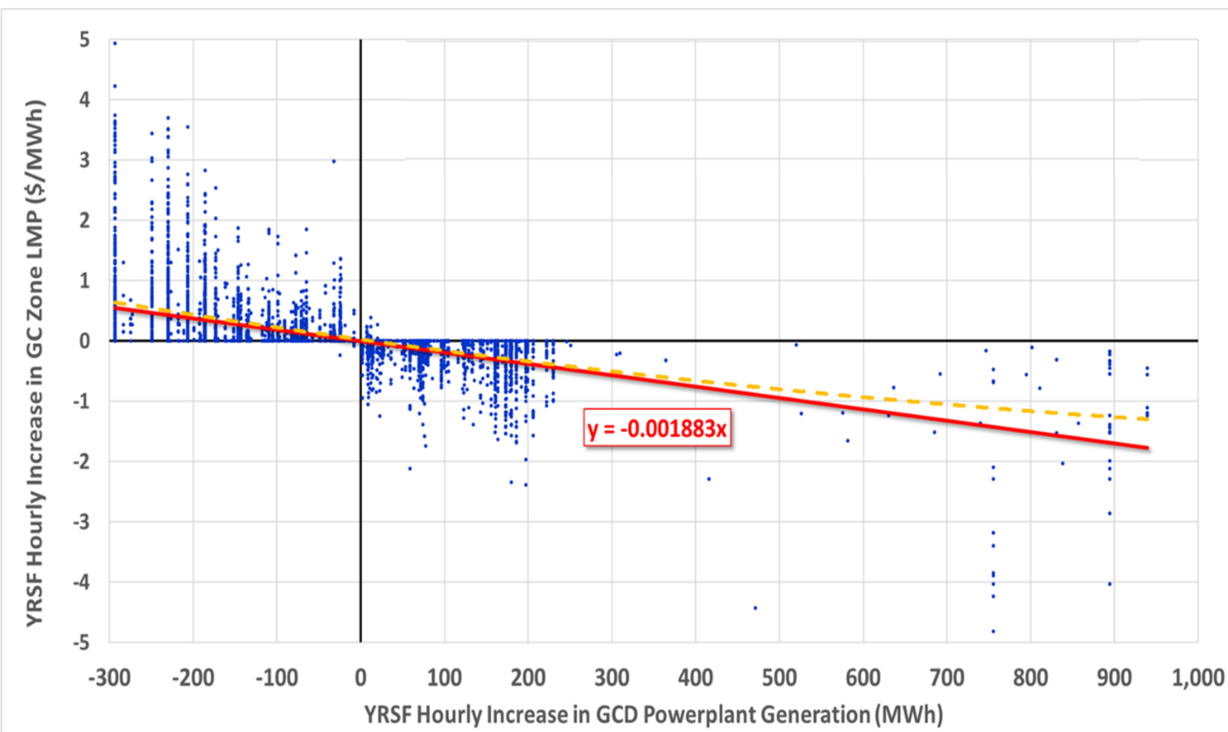
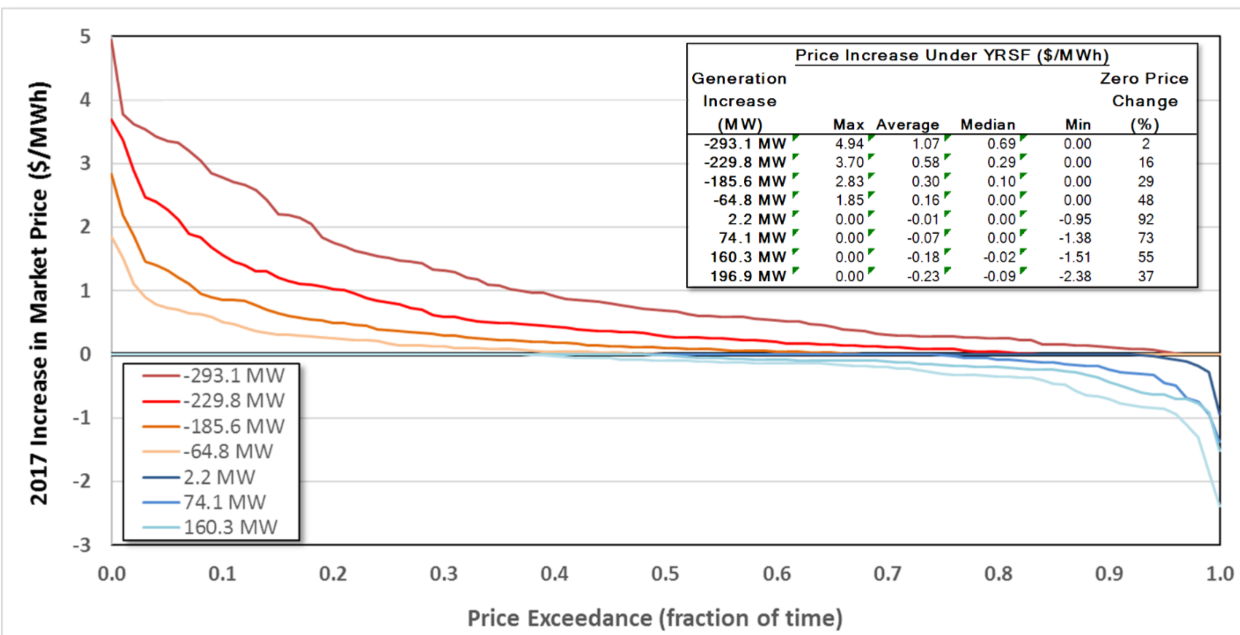


Figure 12-5 Scatter Plot and Least-squares Linear Regression Line of YRSF Generation Changes and Associated Price Increases for All Hours in 2017

Note that Figure 12-5 displays a widening of distribution outcomes as a function of increasing GCD generation changes. This widening of results is further described at several levels of GCD generation changes under the YRSF operating criteria in Figure 12-6. At the negative 293-MW generation change level, grid price responses range from no response to an increase of about $4.9/MWh. Zero price change outcomes at this generation change level occurs only 2% of the time. In contrast, a small positive generation change of about 2 MW resulted in no price response 92% of the time, and a maximum price decrease of less than $1 MW/hr. Further increasing the GCD generation change to 160 MW resulted in a maximum price decrease of about $1.5/MWh, and no response 45% of the time. The curve with the highest GCD generation increase, about 197 MW, shows a maximum price decrease of about $2.4/MWh and no price response 37% of the time.

The wide distribution of price outcomes and price exceedance curves in Figure 12-6 are the result of many factors that, in combination, create a multitude of unique grid conditions that dictate the varied energy price responses. Major factors include, but are not limited to, (1) unit operating status that varies over time as dictated by day-ahead unit commitments, scheduled unit maintenance, and unit outages; (2) monthly/seasonal changes in utility delivered fuel prices; (3) the hourly grid-wide load level; (4) geographical distribution of loads; and (5) transmission limitations.

Although not pertinent for economic calculations, from a financial perspective, individual market players will be impacted differently by changes in GCD operations. Figure 12-7 shows annual price increase statistics for each of the modeled WI zones under the YRSF operating criteria during 2017. The top number in each bubble is the average zonal price under MLFF operating criteria and the middle number is the average price decrease under YRSF operating criteria. The last number in each bubble is the average hourly absolute price decrease. Note that, in general, the further the zone is geographically located from GCD the lower the influence of GCD operations is.



Generation Increase (MW)	Max	Average	Median	Min	Zero Price Change (%)
-293.1 MW	4.94	1.07	0.69	0.00	2
-229.8 MW	3.70	0.58	0.29	0.00	16
-185.6 MW	2.83	0.30	0.10	0.00	29
-64.8 MW	1.85	0.16	0.00	0.00	48
2.2 MW	0.00	-0.01	0.00	-0.95	92
74.1 MW	0.00	-0.07	0.00	-1.38	73
160.3 MW	0.00	-0.18	-0.02	-1.51	55
196.9 MW	0.00	-0.23	-0.09	-2.38	37

(Table title: Price Increase Under YRSF ($/MWh))

Figure 12-6 Price Exceedance Curves for Various Ranges of the GCD Generation Change, 2017

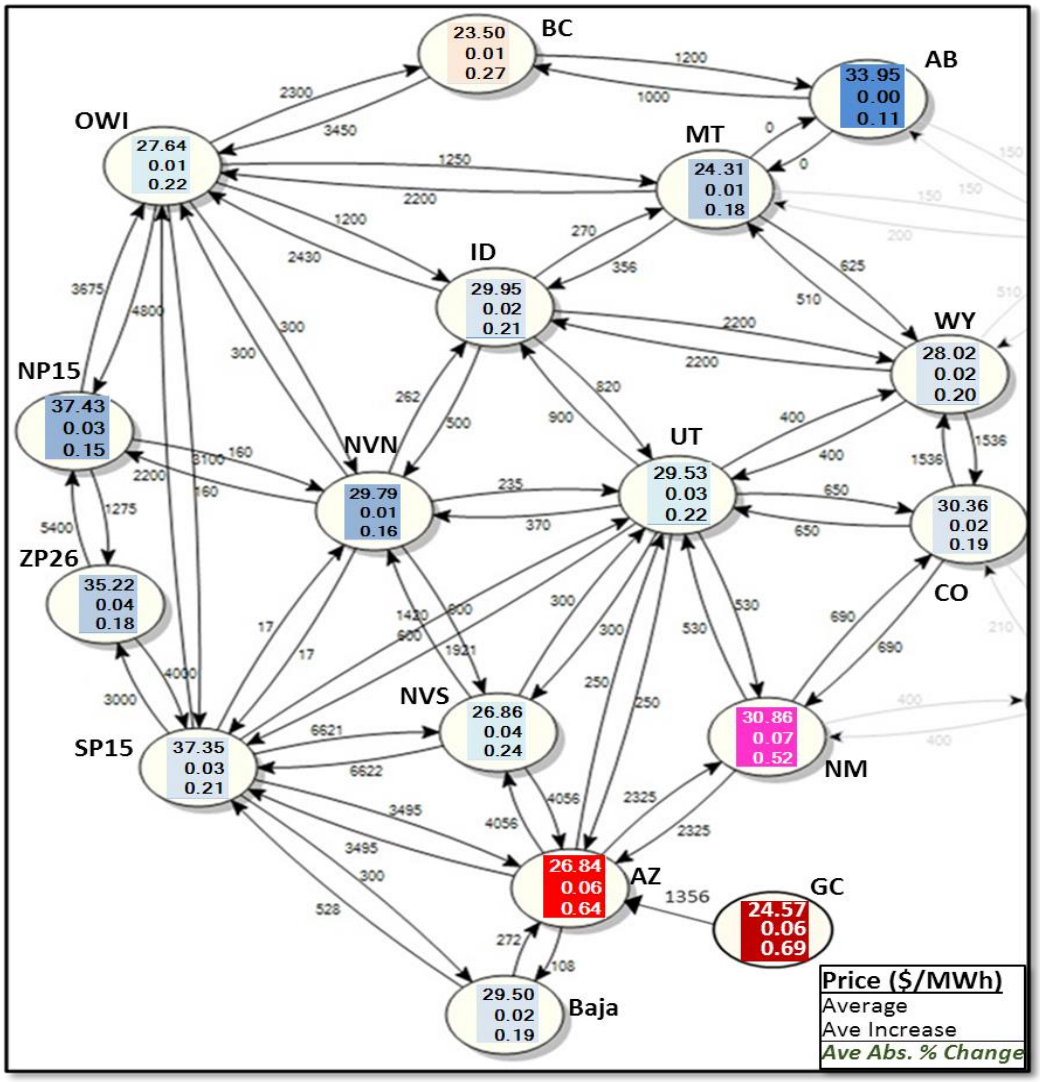


Figure 12-7 Annual Zonal Price Increase Statistics under YRSF Operating Criteria, 2017

The scatter of AURORA model price responses is in part an artifact of both model inputs and model limitations. For example, almost 60% of the time, model results show no change in the GCD prices (i.e., zero LMP reaction), even though there is almost always a change in generation. Despite the thoroughness and complexity of the AURORA model, which uses MILP to solve the problem, this result is imprecise because, as a simplification, the model represents each individual generating unit as multiple blocks that holds operating efficiencies and associated production costs constant for each block.

In reality, when a unit adjusts its operating level, its efficiency level also changes according to the unit's heat-rate curve. The AURORA model does not capture these changes because its homogeneous block structure has a lower level of fidelity than a continuous nonlinear function. The implications of a lower level of fidelity is exacerbated by a lack of site-specific data. In addition to zero price reactions, the lumpy supply curve also contributes to some of the infrequent, but large, price increases shown at the tailend of the frequency distribution in Figure 12-5.

The linear regression analysis was also performed on a monthly basis to refine LMP reaction functions. The implications of a lower level of fidelity are exacerbated by a lack of site-specific data. Unit-level information regarding heat rate curves and other characteristics, such as forced outage rates, are typically proprietary. As an approximation, the generic attributes of various classes of units are typically used as model input data. Therefore, two or more units in the same zone are frequently assigned identical production costs when, in reality, costs differ. It also produces a lumpy supply curve in which there are relatively large flat sections separated by abrupt price changes. Therefore, if one or more units change their output as a result of changed operations at GCD, the lumpy production cost curve at times results in zero LMP change. At other times, it results in exaggerated price changes because operations transverse a segment of the lumpy curve that has an abrupt price change. This may contribute to some of the infrequent, but large, price increases shown at the tailend of the frequency distribution in Figure 12-5.

The linear regression analysis was also performed on a monthly basis to refine LMP reaction functions. Figure 12-8 shows 2017 monthly linear regression slopes and average LMPs. The regression slopes (green bars) have larger negative values during the winter and summer months when prices are relatively high (green line); that is, prices are more sensitive to changed operations at GCD when loads and market prices are high. These results are consistent with this classical utility supply curve, which is convex upward (i.e., slope increases as a function of load).

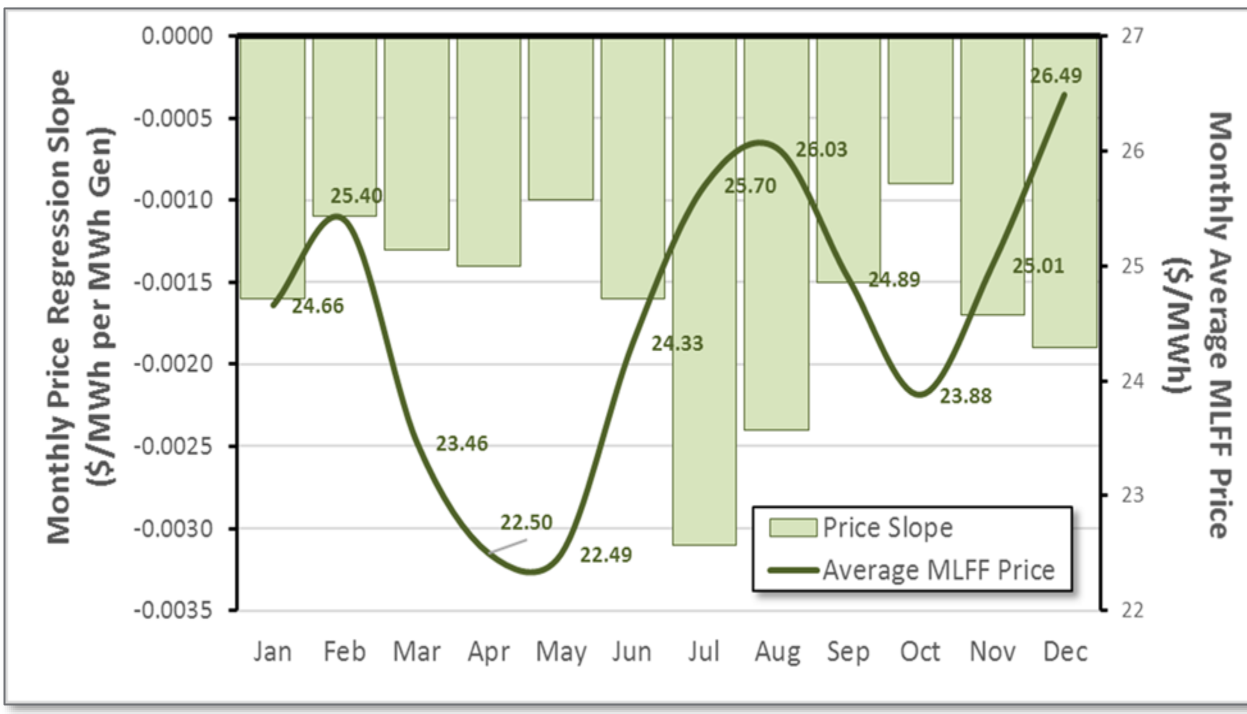


Figure 12-8 Monthly Average MLFF Prices and Linear Regression Slopes under YRSF, 2017

12.2 Hydropower Long-Run Impacts: Replacement Capacity Impacts on LMP

In addition to short-term hydropower and grid interactions such as those discussed above, there are also long-term grid implications that affect grid operations indefinitely. The removal of hydropower capacity and the eventual replacement of the lost firm capacity impacts the grid dispatch, and therefore system production costs.

Prior to the time when hydropower replacement capacity is online (i.e., during the excess capacity period, Figure 2-18), systemwide production costs are higher because lower supplies essentially translate into higher economic costs. In general, this occurs in power systems because the energy generated by a very low-cost hydropower plant must be instead produced by resources that are more expensive to operate. The utilization of more expensive resources also drives market prices higher. However, there are exceptions when hydropower generation is detrimental to the grid, such as cases when there is on oversupply of energy injections into the grid from VERs and base load units that are expensive to start and stop.

After hydropower replacement capacity has been built and has come online, production costs under some grid conditions/hours may decrease along with energy market prices. This decrease is illustrated by a comparision of Figure 12-9 (without replacement capacity) with Figure 12-10. The decreases sometimes occurs because, for all practical purposes, some replacement technologies such as natural-gas combined cycle do not have the fuel/water limits and constraints that bind hydropower plant operations. For example, a new natural-gas combined-cycle plant may operate at its physical maximum output level whenever it is operable. It therefore has the potential to displace generation from old, expensive units more often. and sometimes at a higher level than the displaced hydropower plant. Production costs and prices are affected the most when highly efficient and inexpensive replacement capacity is built in a grid that has existing resources that are expensive to operate; that is, the replacement capacity can displace generation from expensive units in more hours than energy-limited hydropower plants.

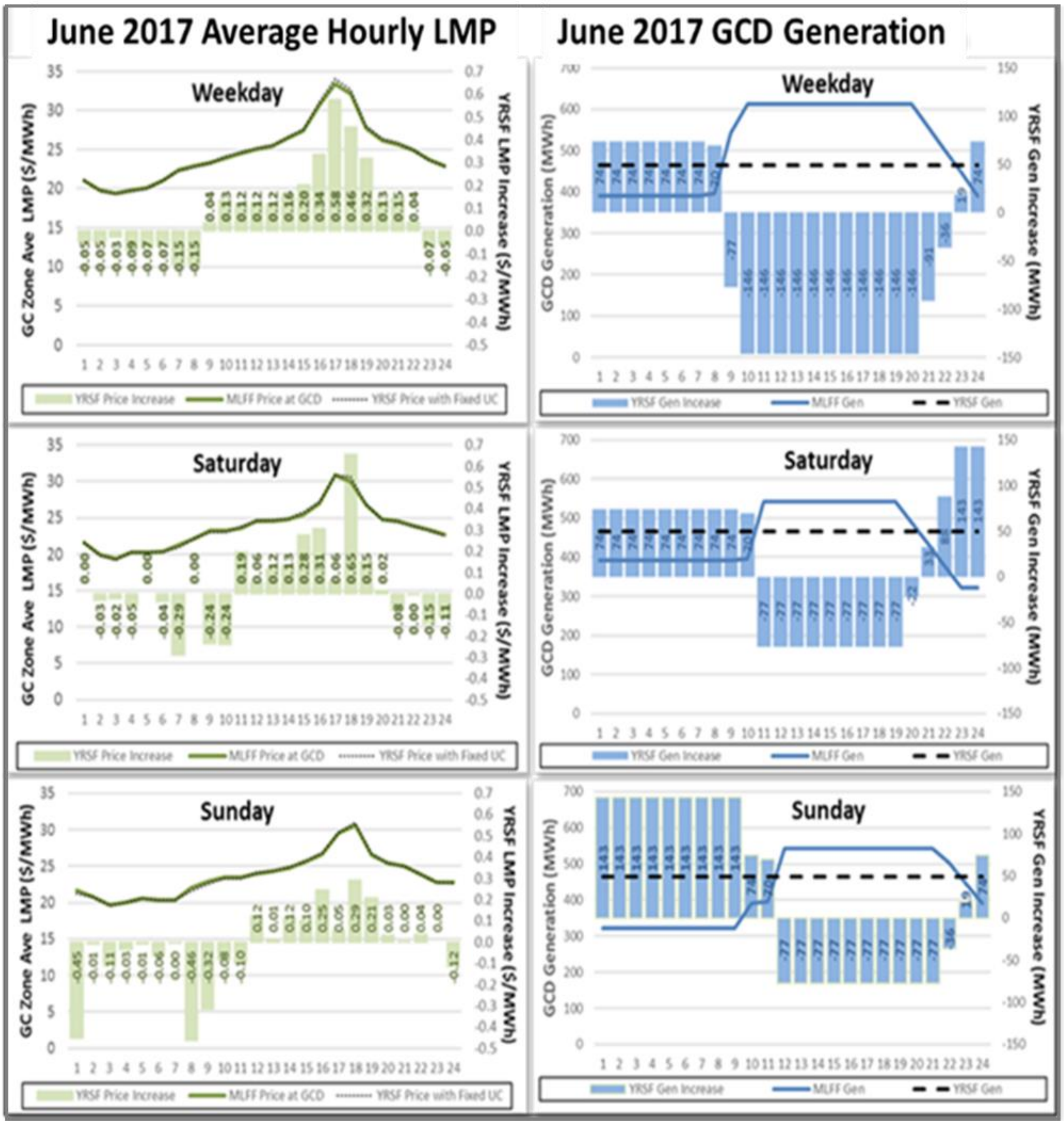


Figure 12-9 Impact of YRSF Replacement Capacity on LMPs at GCD, without GCD Capacity Replacement

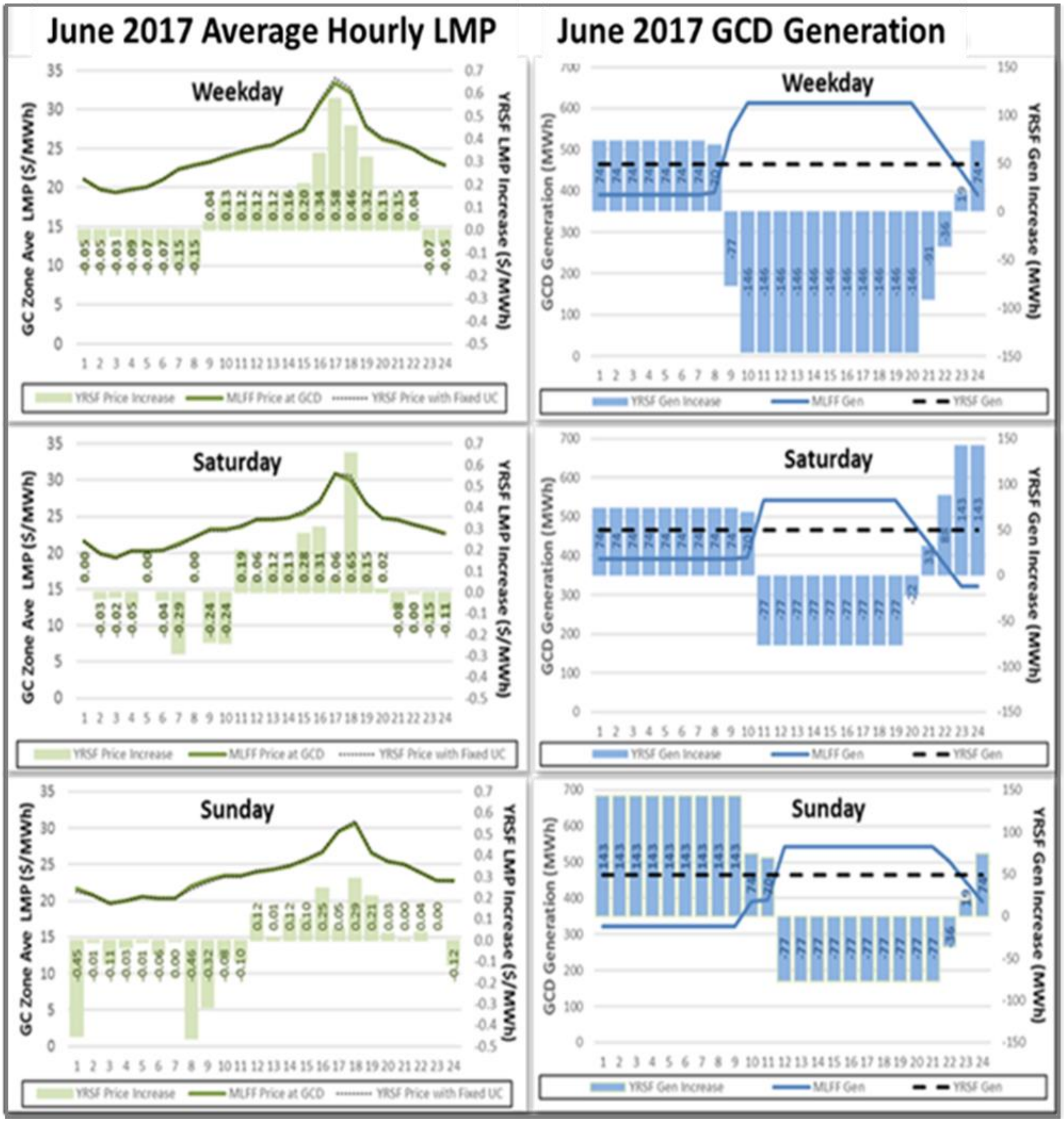


Figure 12-10 Impact of YRSF Replacement Capacity on LMPs at GCD, with CCCT GCD Capacity Replacement

This page left intentionally blank.

13.0 Conclusion

Hydropower energy production enables cleaner, more efficient, and less costly grid-level dispatch through optimal use of power plant operational capabilities within physical and institutional constraints such as environmental operating criteria. The 101 GW of hydropower capacity in the United States generates energy to serve system load, provide ancillary services to enhance system reliability, contribute toward flexibility reserves for VER grid integration, and satisfy other grid needs such as load following, inertia, and volt-ampere reactive support. Currently, hydropower energy production serves about 7.1% of the total U.S. annual electricity demand, about 60% of which is generated in the WECC. The WECC also has the highest regional reliance on hydropower production accounting for, on average, almost 25% of its total regional electricity production.

The economic value of hydropower energy production is its social value, which is an integral part of modern life. This is captured by the value of foregone opportunity: the cost to produce power by the next best alternative supply resource. Because electricity on a utility scale cannot be stored economically in large quantities it differs from other types of goods. Electricity demand at every consumption point and at every time electrical demand exists must be balanced with supply in order to avoid societal/economic disruptions. In this regard, electrical capacity serves the public good (in the economic sense).

From a strictly grid perspective, operational hydropower plants yield a net positive economic value on time scales ranging from fractions of a second to several decades by providing an interconnected system with capacity, energy, ancillary services, and other support functions (e.g., inertia). Economic value, however, varies widely among U.S. hydropower plants. It depends on many factors including, but not limited to, temporal water availability, plant operational flexibility, generating unit water-to-power conversion efficiency, location, and the characteristics of power grid in which it resides. Dispatchable hydropower plants that produce energy and provide grid services during peak/high-price periods have the highest value.

The characteristics of hydropower make it unique compared to other power supply resources such as thermal power technologies; hydropower energy production is limited by the availability of scarce water resources. Because water is limited, sound management and strategic water releases patterns over time are essential for maximizing the value of water and hydropower energy production/capacity including set-point deviations that support grid services and other system needs.

Hydropower value streams primarily include firm capacity, energy production, and ancillary services, the economics of which are described in this report as avoided grid costs. The avoided cost approach measures the interconnection level economic impacts that would occur if an existing hydropower resource is removed from the grid. It uses a systemic approach based on a comparison of total grid unit-commitment and production costs between “with” (factual) and “without” (counterfactual) hydropower resource cases. From an operational perspective, all avoided costs attributed to hydropower are reflected in grid-level changes in production that are encapsulated in the system dispatch as a single bundled reduction in system-level production cost.

Hydropower capacity has value in its ability to produce electricity and indefinitely delays/alters the construction of new supply resources. Its value is therefore linked to cost of building a replacement power plant with equal characteristics. This presumes that construction costs are the same as market value and that market value is the same as social value. These assumptions are valid under conditions of fair, competitive markets such as those in the United States.

Capacity credit, in terms of megawatts, awarded to a hydropower plant is highly dependent on the plant's characteristics and associated reservoir attributes, hydrological/water storage conditions at the time of peak load, and the system that the hydropower plant is located. Because the conditions that drive hydropower plant maximum output levels are variable and uncertain, the firm capacity credit of a plant is typically based on the risk tolerance of system long-term planners; that is, it is based on the probability that the projected energy production level will be at the firm capacity level or greater during the time of the system peak demand.

Because hydrological conditions vary across a footprint/system over time, system-level hydropower firm capacity credit is often based on probability distributions of simultaneous total production levels from a group of plants. This approach typically results in a higher capacity credit for the aggregated resource versus the sum of individual plant capacity credits. In general, larger footprints that have diverse hydrological conditions result in a higher aggregate firm capacity credit relative to smaller more homogeneous regions.

The timing of replacement capacity considers when capacity additions are needed to meet reliability targets and the type of replacement capacity technology that minimizes the NPV of system costs over a period of two or more decades. Depending on anticipated grid changes and the availability of data, probability distributions of peak hydropower production levels and associate economic value may be based on either historical data or simulations of future operations using methods that range from relatively simple spreadsheet calculations to sophisticated capacity expansion and production cost models.

When a hydropower plant is replaced by thermal capacity, such as a new generating unit or power plant that utilizes an efficient natural gas technology, system production costs and prices/marginal costs tend to decrease. Dispatch saving from new, very efficient technologies without fuel limitations can significantly reduce or even eliminate the capacity value of hydropower; that is, system production cost savings over the lifetime of the replacement plant can potentially be equal to or greater than replacement capacity construction costs.

Although hydropower plants have a marginal production cost that is near zero, it is not always dispatched because it uses a scare energy resource (i.e., flowing water). Because of this water limitation, hydropower energy value is maximized when it is uses scare water resource for energy production during times when electricity production by the next-best, relatively expensive alternative supply resource. In other words, U.S. hydropower generation has economic value because it displaces the energy that would otherwise have been produced by more-expensive resources in the grid. It thereby reduces total grid generation costs. For example, fuel expenditures and variable O&M costs are not incurred when a hydropower energy displaces energy that would have otherwise been produced by a thermal plant.

By displacing power produced by the next-best alternative supply resource, hydropower also reduces locational marginal costs. In general, the higher the hydropower production, the lower the LMP. The reduction in the LMP is typically the highest at the hydropower plant site and decreases as a function of distance from the plant. In addition, the incremental decreases in LMP tends to diminish as more hydropower is injected into the grid.

Reservoirs that store scarce water resources increase water and hydropower value streams. Relative to natural inflow, reservoirs enable planners and operators to manage the timing and routing of water through dams such that less water bypasses the plant turbines. This, in turn, leads to higher overall monthly/annual production levels. Production levels can also be shaped such that generation is relatively high when it is needed most by the grid, as reflected in seasonal and diurnal LMP profiles. Depending on the size of the reservoir, it increases value on time scales ranging from a few hours to multiple years.

Some hydropower plants are governed by environmental operating criteria that constrain or alter plant operations. For peaking hydropower plants with reservoir water storage, these criteria may restrict monthly, daily, and hourly temporal water releases. They typically, but not always, do so by reducing hydropower economic value in two ways. First, the hydropower energy cannot be used fully during hours of peak electricity demand when the market price and economic benefits are relatively high. Second, there is typically a loss of firm capacity credit when criteria limit maximum output levels. As a result, this lost capacity must eventually be replaced by other power supply resources or the implementation of additional DSM initiatives.

Hydropower plants that have operational flexibility can provide valuable ancillary services for the grid. Capacity reserves needed for regulation, flexibility reserves, and load flowing may increase in the future as VER penetration levels grow, potentially increasing grid costs. By dynamically estimating asymmetrical flexibility/regulation-up and regulation-down requirements, both peaking and pumped storage hydropower plants can play a major role in reducing VER integration costs.

Changes in market structures such as shortening the dispatch time interval and expanding the dispatch footprint as implemented by the CAISO EIM can also reduce VER grid integration costs, contribute to system reliability, and increase VER penetration potentials. Markets that span multiple BAs also allow hydropower resources in one BA to resolve energy imbalances in other BAs that have very little or no hydropower resources. These changes in the grid supply/demand resource mix and evolving power market structures/rules may potentially increase both the financial and economic value of hydropower in the grid of the future.

This page left intentionally blank.

Available electronically at OSTI.gov http:/www.osti.gov

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
OSTI http://www.osti.gov
Phone: 865.576.8401
Fax: 865.576.5728
Email: reports@osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
NTIS http://www.ntis.gov
Phone: 800.553.6847 or 703.605.6000
Fax: 703.605.6900
Email: orders@ntis.gov

Energy Systems Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 362
Argonne, IL 60439

www.anl.gov

https://www.energy.gov/eere/water/hydrowires-initiative

HydroWIRES

U.S. DEPARTMENT OF ENERGY